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, 2021
or

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

Commission File Number	Name of Registrant; State or Other Jurisdiction of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
001-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
001-01839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 10 South Dearborn Street 49th Floor Chicago, Illinois 60603-2300 (312) 394-4321	36-0938600
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
001-01910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210
001-31403	PEPCO HOLDINGS LLC (a Delaware limited liability company) 701 Ninth Street, N.W. Washington, District of Columbia 20068-0001 (202) 872-2000	52-2297449
001-01072	POTOMAC ELECTRIC POWER COMPANY (a District of Columbia and Virginia corporation) 701 Ninth Street, N.W. Washington, District of Columbia 20068-0001 (202) 872-2000	53-0127880
001-01405	DELMARVA POWER & LIGHT COMPANY (a Delaware and Virginia corporation) 500 North Wakefield Drive Newark, Delaware 19702-5440 (202) 872-2000	51-0084283
001-03559	ATLANTIC CITY ELECTRIC COMPANY (a New Jersey corporation) 500 North Wakefield Drive Newark, Delaware 19702-5440 (202) 872-2000	21-0398280

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
EXELON CORPORATION:		
Common Stock, without par value	EXC	The Nasdaq Stock Market LLC
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 ☐
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 ☒
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 ☐
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, 2021 was as follows:

Exelon Corporation Common Stock, without par value	$43,290,833,498
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, 2022 was as follows:

Exelon Corporation Common Stock, without par value	980,136,968
Commonwealth Edison Company Common Stock, $12.50 par value	127,021,391
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 2021 Annual Meeting of Shareholders and the Commonwealth Edison Company 2021 Information Statement are incorporated by reference in Part III.

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	Constellation Energy Generation, LLC (formerly Exelon Generation Company, LLC, a subsidiary of Exelon as of December 31, 2021 prior to separation on February 1, 2022)
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, 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.
CR	Constellation Renewables, LLC (formerly ExGen Renewables IV, LLC)
CRP	Constellation Renewables Partners, LLC (formerly ExGen Renewables Partners, LLC)
EEDC	Exelon Energy Delivery Company, 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, LLC
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.
BSA	Bill Stabilization Adjustment
CAISO	California ISO
CBAs	Collective Bargaining Agreements
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
CMC	Carbon Mitigation Credit
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
DEPSC	Delaware Public Service Commission
DOE	United States Department of Energy
DOEE	Department of Energy & Environment
DOJ	United States Department of Justice
DPP	Deferred Purchase Price
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
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
LTRRPP	Long-Term Renewable Resources Procurement Plan
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
MPSC	Missouri Public Service Commission
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
NGX	Natural Gas Exchange
NJBPU	New Jersey Board of Public Utilities
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
OCEP	Oyster Creek Environmental Protection, LLC
OCI	Other Comprehensive Income

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
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
PUCT	Public Utility Commission of Texas
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)
SNF	Spent Nuclear Fuel
SOA	Society of Actuaries
SOFR	Secured Overnight Financing Rate
SOS	Standard Offer Service
SPP	Southwest Power Pool
SSA	Social Security Administration
STRIDE	Maryland Strategic Infrastructure Development and Enhancement Program
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

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

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
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, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants). Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING INFORMATION

This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. Words such as “could,” “may,” “expects,” “anticipates,” “will,” “targets,” “goals,” “projects,” “intends,” “plans,” “believes,” “seeks,” “estimates,” “predicts,” 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

As of December 31, 2021, Exelon was 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.

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 was completed on February 1, 2022 and gives each company the financial and strategic independence to focus on its specific customer needs, while executing its core business strategy. See Note 26 – Separation of the Combined Notes to Consolidated Financial Statements for additional information.

Name of Registrant / Subsidiary	Business	Service Territories
Commonwealth Edison Company (registrant)	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 (registrant)	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 (registrant)	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 (registrant)	Utility services holding company engaged, through its reportable segments Pepco, DPL, and ACE	Service Territories of Pepco, DPL, and ACE
Potomac Electric Power Company (registrant)	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 (registrant)	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 (registrant)	Purchase and regulated retail sale of electricity	Portions of Southern New Jersey
	Transmission and distribution of electricity to retail customers	
Constellation Energy Generation, LLC (formerly Exelon Generation Company, LLC) (subsidiary)	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

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 and associated attributes, in competitive domestic energy markets to both wholesale and retail customers. Generation leverages its generation portfolio to serve customers under both long-term and short-term contracts, as well as spot market sales. Generation operates in well-developed energy markets and employs integrated and ratable hedging strategies to manage commodity price volatility. Generation's fleet also provides geographic and supply source diversity. Generation’s customers include distribution utilities, municipalities, cooperatives, 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 as defined 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, 2021, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets[(a)]	
Nuclear	20,899
Fossil (primarily natural gas and oil)	8,819
Renewable[(b)]	2,682
Owned generation assets	32,400
Contracted generation[(c)]	4,102
Total generating resources	36,502

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

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

(c) Electric supply procured under unit-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	10,508	32 %	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	11,898	37 %	Western half of PJM and the United States footprint of MISO, excluding MISO’s Southern Region
New York	3,093	10 %	NYISO
ERCOT	3,610	11 %	Electric Reliability Council of Texas
Other Power Regions	3,291	10 %	New England, South, West, and Canada
Total	32,400	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 20,899 MW of capacity. These stations 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 four jointly-owned nuclear stations: Quad Cities (75% ownership), Peach Bottom (50% ownership), Salem (42.59% ownership), and Nine Mile Point Unit 2 (82% ownership), which are consolidated in Exelon’s financial statements relative to its proportionate ownership interest in each unit.

Generation had 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. EDF had 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 August 6, 2021, Generation and

EDF entered into a settlement agreement pursuant to which Generation, through a wholly owned subsidiary, purchased EDF’s equity interest in CENG for a net purchase price of $885 million.

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 acquisition of EDF's equity interest in CENG and 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 2021, 2020, and 2019 electric supply (in GWh) generated from the nuclear generating facilities was 65%, 62%, and 64%, 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 2021, 2020, and 2019, the nuclear generating facilities operated by Generation, achieved capacity factors of 94.5%, 95.4%, and 95.7%, 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.

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	1975	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 received a Timely Renewal Exemption from the NRC that allows for the license renewal application to be filed in the first quarter of 2024.

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 corresponds with the term of the NRC operating licenses denoted in the table above as of December 31, 2021. From August 27, 2020 through September 15, 2021, Byron and Dresden depreciation provisions were accelerated to reflect the previously announced shutdown dates of September 2021 and November 2021, respectively. On September 15, 2021, Generation updated the expected useful lives for both facilities to reflect the end of the available NRC operating license for each unit consistent with the table above. See Note 7 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information on Byron and Dresden.

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, 2021, Generation had approximately 89,400 SNF assemblies (21,900 tons) stored on site in SNF pools or wet and dry cask storage which includes SNF assemblies at Zion Station, for which Generation retains ownership and responsibility for the decommissioning of the Zion Independent Spent Fuel Storage Installation. 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 2022. 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 2040 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.

Fossil and Renewable Facilities (including Hydroelectric)

Generation wholly owns all its fossil and renewable generating stations, except for: (1) Wyman; (2) certain wind project entities; and (3) CRP, 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 CRP which is a VIE. Generation's fossil and renewable generating stations are all operated by Generation, except for Wyman, which is operated by the principal owner, NextEra Energy Resources LLC, a subsidiary of the FPL Group, Inc. In 2021, 2020, and 2019, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 10%, 9%, and 11%, respectively, of Generation's total electric supply. Much of this output was dispatched to support Generation's wholesale and retail power marketing activities. On March 31, 2021 and June 30, 2021, Generation completed the sale of a significant portion of its solar business and its interest in the Albany Green Energy biomass facility, respectively. 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 these dispositions.

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 and Conowingo's on February 28, 2071. The stations are currently being depreciated over their estimated useful lives, which correspond with the license terms. 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. 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, 2021:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic	7	2022 - 2032	176
Midwest	3	2026 - 2032	351
New York	4	2022	26
ERCOT	5	2022 - 2035	864
Other Power Regions	12	2022 - 2033	2,685
Total	31		4,102

	2022	2023	2024	2025	2026	Thereafter	Total
Capacity Expiring (MW)	1,084	114	101	490	398	1,915	4,102

Fuel

The following table shows sources of electric supply in GWh for 2021 and 2020:

	Source of Electric Supply	
	2021	2020
Nuclear[a]	174,987	175,085
Purchases — non-trading portfolio	67,605	79,972
Fossil (primarily natural gas and oil)	19,960	19,501
Renewable[b]	6,577	7,052
Total supply	269,129	281,610

(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.

(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 and natural gas. 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 and its ratable hedging program. 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.

Price and Supply Risk Management

Generation uses a combination of wholesale and retail customer load sales, as well as 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 the price risk of the generation portfolio. 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 hedging program.

A portion of Generation’s hedging strategy may be implemented using fuel products based on assumed correlations between power and fuel prices. The risk management group monitors 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.

Utility Registrants

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, 2021:

	ComEd	PECO	BGE	Pepco	DPL	ACE
Service Territories (in square miles)						
Electric	11,450	2,100	2,300	650	5,400	2,750
Natural Gas	N/A	1,900	3,050	N/A	250	N/A
Total[a]	11,450	2,100	3,250	650	5,400	2,750
Service Territory Population (in millions)						
Electric	9.3	4.0	3.0	2.4	1.5	1.2
Natural Gas	N/A	2.5	2.9	N/A	0.6	N/A
Total[b]	9.3	4.0	3.1	2.4	1.5	1.2
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[c]	4.1	1.7	1.3	0.9	0.5	0.6

(a) The number of total service territory square miles counts once only a square mile that includes both electric and natural gas services, and thus does not represent the combined total square mileage of electric and natural gas service territories.

(b) The total service territory population counts once only an individual who lives in a region that includes both electric and natural gas services, and thus does not represent the combined total population of electric and natural gas service territories.

(c) The number of total customers counts once only a customer who is both an electric and a natural gas customer, and thus does not represent the combined total of electric customers and natural gas customers.

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	DEPSC/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. The U.S. Department of Homeland Security (Transportation Security Administration) provided new security directives in 2021 that regulate cyber risks for certain gas distribution operators. 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, DPL Maryland, and ACE 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, DPL Maryland's, and ACE's electric distribution revenues and BGE's natural gas distribution revenues are not materially impacted by delivery volumes. PECO's and DPL Delaware's electric distribution revenues and natural gas 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. On September 15, 2021, Illinois passed the Clean Energy Law, which contains requirements for ComEd to transition away from the performance-based rate formula by the end of 2022 and would allow for the submission of either a general rate or multi-year rate plan. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information. 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, DPL and ACE customers have the choice to purchase electricity, and PECO and BGE customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. DPL customers, with the exception of certain commercial and industrial customers, do not have the choice to purchase natural gas from competitive 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, BGE, and DPL 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 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 from customers without mark-up or with a slight mark-up and therefore record the amounts in Operating revenues and Purchased power and fuel expense. As a result, fluctuations in electricity or natural gas sales and procurement costs have no significant 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 137,000 mmcf, 268,000 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 2021-2022 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 2022 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 FERC approved formula as shown below:

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

Exelon’s Strategy and Outlook

In 2021, the businesses remained 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 strategy is to improve reliability and operations, enhance the customer experience, and advance clean and affordable energy choices, 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, improved service for our customers, increased capacity to accommodate new technologies, and a stable return for the company.

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

The Utility Registrants anticipate investing approximately $29 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 $17 billion by the end of 2025. 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.

In August 2021, the Utility Registrants announced a “path to clean” goal to collectively reduce their operations-driven emissions 50% by 2030 against a 2015 baseline, and to reach net zero operations-driven emissions by 2050. This goal builds upon Exelon’s long-standing commitment to reducing our GHG emissions. See ITEM 1. BUSINESS — Environmental Matters and Regulation — Climate Change for additional information.

Various market, financial, regulatory, legislative and operational factors could affect Exelon's success in pursuing its strategies. Exelon continues to assess infrastructure, operational, policy, and legal solutions to these issues. See ITEM 1A. RISK FACTORS for additional information.

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 generally 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, 2021. The Exelon numbers include all subsidiaries, including Generation.

Employees	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Female(a) (b)	7,892	1,505	752	753	1,269	339	143	105
People of Color(b)	9,436	2,464	929	1,115	1,760	873	196	139
Aged <30	3,236	653	315	280	413	169	87	58
Aged 30-50	17,008	3,566	1,337	1,728	2,241	748	458	361
Aged >50	11,274	2,037	1,157	1,120	1,532	472	365	214
Total Employees(c)	31,518	6,256	2,809	3,128	4,186	1,389	910	633

Management(d)	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Female(a) (b)	1,242	219	123	116	179	49	11	19
People of Color(b)	1,233	308	117	146	246	113	27	20
Aged <30	73	6	7	1	8	3	—	2
Aged 30-50	2,857	469	157	256	356	105	58	44
Aged >50	2,107	365	194	161	266	67	59	40
Within 10 years of retirement eligibility	2,876	497	239	226	368	92	74	53
Total Employees in Management(c)	5,037	840	358	418	630	175	117	86

(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 2019 to 2021. The Exelon numbers include all subsidiaries, including Generation.

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Retirement Age	4.27 %	3.82 %	3.47 %	3.70 %	4.02 %	4.37 %	4.10 %	3.17 %
Voluntary	2.98 %	1.49 %	1.76 %	1.36 %	2.06 %	2.36 %	1.11 %	1.20 %
Non-Voluntary	0.98 %	0.56 %	1.06 %	0.94 %	0.96 %	1.87 %	0.32 %	0.68 %

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, 2021. The Exelon numbers include all subsidiaries, including Generation.

	Total Employees Covered by CBAs	Number of CBAs	CBAs New and Renewed in 2021[a]	Total Employees Under CBAs New and Renewed in 2021
Exelon	11,770	32	8	6,476
ComEd	3,478	2	2	3,478
PECO	1,351	2	2	1,351
BGE	1,416	1	—	—
PHI	2,161	5	—	—
Pepco	929	1	—	—
DPL	631	2	—	—
ACE	387	2	—	—

(a) Does not include CBAs that were extended in 2021 while negotiations are ongoing for renewal.

Environmental Matters and Regulation

On February 21, 2021, Exelon's Board of Directors approved a plan to separate the Utility Registrants and Generation, creating two publicly traded companies. The separation was completed on February 1, 2022. See Note 26 — Separation of the Combined Notes to Consolidated Financial Statements for additional information. As such, the disclosures below do not include disclosures associated with Generation.

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 and Chief Strategy and Sustainability Officer; as well as senior management of the Utility 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 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

As detailed below, the Registrants face climate change mitigation and transition risks as well as adaptation risks. Mitigation and transition risks include changes to the energy systems as a result of new technologies, changing customer expectations and/or voluntary GHG goals, as well as local, state or federal regulatory requirements intended to reduce GHG emissions. Adaptation risk refers to risks to the Registrants' facilities or operations that may result from changes in the physical climate, such as changes to temperature, weather patterns and sea level.

Climate Change Mitigation and Transition

The Registrants support comprehensive federal climate legislation 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. GHG emission sources associated with the 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 consumers' use of such natural gas produces GHG emissions.

Since its inception, Exelon has positioned itself as a leader in climate change mitigation. In 2020, Exelon's Scope 1 and 2 GHG emissions, as revised following the separation, were just over 5.6 million metric tons carbon dioxide equivalent using the World Resources Institute Corporate Standard Market-based accounting. Of these emissions, 551,000 metric tons are considered to be operations-driven and in more direct control of our employees and processes. The remaining 5 million metric tons, approximately 90%, are the indirect emissions associated with electric distribution and transmission system uses and losses resulting from the Utility Registrant's delivery of electricity to their customers. These system uses and losses are driven primarily by customer use and generation assets on the grid that are not under our ownership.

In August 2021, the Utility Registrants announced a "path to clean" goal to collectively reduce their operations-driven emissions 50% by 2030 against a 2015 baseline, and to reach net zero operations-driven emissions by 2050, while also supporting customers and communities to achieve their clean energy and emissions goals. This goal builds upon Exelon's long-standing commitment to reducing our GHG emissions. The Utility Registrants "path to clean" will include efficiency and clean electricity for operations, vehicle fleet electrification, equipment and processes to reduce sulfur hexafluoride (SF6) leakage, modern natural gas infrastructure to minimize methane leaks and increase safety and reliability, and investment and collaboration to develop new technologies. Over the next 10 years, Exelon anticipates investing approximately $4.8 billion towards its "path to clean" goal. Exelon believes it has line of sight into solutions available today to achieve 80% of its "path to clean" goal and that achieving full net-zero operations will require some technology advancement and continued policy support. Exelon is laying the groundwork by partnering with national labs, universities and research consortia to research, develop and pilot clean technologies. The Utility Registrants are also driving customer-driven emissions reductions in their communities through some of the nation's largest energy efficiency programs. During 2022 - 2025, estimated energy efficiency investments across the Utility Registrants total $3.4 billion. These programs enable customer savings through home energy audits, lighting discounts, appliance recycling, home improvement rebates, equipment upgrade incentives and innovative programs like smart thermostats and combined heat and power programs.

The electric sector plays a key role in lowering GHG emissions across much of the economy. Electrification, where feasible for transportation, buildings, and industry coupled with simultaneous decarbonization of electric generation can be a key lever for emissions reductions. To support this transition, Exelon is advocating for public policy supportive of vehicle electrification, investing in enabling infrastructure and technology, and supporting customer education and adoption. In addition, the Utility Registrants will electrify 30% of their own vehicle fleet by 2025, increasing to 50% by 2030. Exelon also continues to explore other decarbonization opportunities, supporting pilots of emerging energy technologies and clean fuels to support both operational and customer-driven emissions reductions.

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, and the United States has now set an economy-wide target of reducing its net GHG emissions by 50-52% below 2005 levels by 2030. The 2021 UNFCCC Conference of the Parties (COP26) and resulting Glasgow Climate Pact indicated important global support for the Paris Agreement and continued progress toward decarbonization.

Federal Climate Change Legislation and Regulation. It is uncertain whether federal legislation to significantly reduce GHG emissions will be enacted in the near-term. On November 15, 2021, President Biden signed the Infrastructure Investment and Jobs Act's (IIJA) into law, which does include provisions intended to address climate change. Exelon anticipates pursuing opportunities under IIJA.

Regulation of GHGs from Power Plants under the Clean Air Act. 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. On October 29, 2021, the Supreme Court granted certiorari to examine the extent of EPA's authority to regulate GHGs from power plants; a decision is expected in 2022. The EPA has indicated it will promulgate new GHG limits for existing power plants. Increased regulation of GHG emissions from power plants could increase the cost of electricity delivered or sold by The Registrants. As of February 1, 2022, the Registrants no longer directly own electric generation plants.

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.

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, which is anticipated to support Pennsylvania's participation in RGGI beginning sometime in 2022.

Broader state programs impact other sectors as well, such as the District of Columbia's Clean Energy DC Omnibus Act and cross-sector GHG reduction plans, which resulted in recent requirements for Pepco to develop 5-year and 30-year decarbonization programs and strategies. Maryland has a statewide GHG reduction mandate to reduce GHG emissions by 40% no later than 2030, which it expects to meet and surpass. New Jersey accelerated its goals through Executive Order 274, which establishes an interim goal of 50% reductions below 2006 levels by 2030 and affirms its goal of achieving 80% reductions by 2050 and includes programs to drive greater amounts of electrified transportation. Finally, the Clean Energy Law establishes decarbonization requirements for Illinois as well as programs to support the retention and development of emissions-free sources of electricity. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Clean Energy Law.

The Registrants cannot predict the nature of future regulations or how such regulations might impact future financial statements.

Renewable and Clean Energy Standards. The 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. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Climate Change Adaptation

The Registrants' facilities and operations are subject to the global impacts of climate change. Long-term shifts in climactic patterns, such as sustained higher temperatures and sea level rise, may present challenges for the Registrants and their service territories. Exelon believes its operations could be significantly affected by the physical risks of climate change. See ITEM 1A. RISK FACTORS, The Registrants are subject to risks associated with climate change, for additional information.

The Registrants' assets undergo seasonal readiness efforts to ensure they are ready for the weather projections of the summer and winter months. The Registrants consider and review national climate assessments to inform their planning. Each of the Utility Registrants also has well establish system recovery plans and is investing in its systems to install advanced equipment and reinforce the local electric system, making it more weather resistant and less vulnerable to anticipated storm damage.

Other Environmental Regulation

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 water into waterways and are therefore subject to these regulations and operate under NPDES permits.

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.

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 2022 for compliance with environmental remediation related to contamination at former MGP sites and other gas purification sites is estimated to be approximately $54 million which consists primarily of $48 million at ComEd.

As of December 31, 2021, 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 25, 2022

Exelon

Name	Age	Position	Period
Crane, Christopher M.	63	Chief Executive Officer, Exelon;	2012 - Present
		President, Exelon	2008 - Present
Butler, Calvin G.	52	Senior Executive Vice President, Exelon; Chief Operations Officer, Exelon	2021 - Present
		Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities	2019 - 2021
		Chief Executive Officer, BGE	2014 - 2019
Glockner, David	61	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
Littleton, Gayle E.	49	Executive Vice President, General Counsel, Exelon	2020- Present
		Partner, Jenner & Block LLP	2015 -2020
Quiniones, Gil	55	Chief Executive Officer, ComEd	2021 - Present
		President and Chief Executive Officer, New York Power Authority	2011 - 2021
Innocenzo, Michael A.	56	President and Chief Executive Officer, PECO	2018 - Present
		Senior Vice President and Chief Operations Officer, PECO	2012 - 2018
Khouzami, Carim V.	46	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
Anthony, J. Tyler	57	President and Chief Executive Officer, PHI	2021 - Present
		Senior Vice President and Chief Operating Officer, PHI, Pepco, DPL, and ACE	2016 - 2021
Nigro, Joseph	57	Senior Executive Vice President and Chief Financial Officer, Exelon	2018 - Present
		Executive Vice President, Exelon; Chief Executive Officer, Constellation	2013 - 2018
Souza, Fabian E.	51	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

ComEd

Name	Age	Position	Period
Quiniones, Gil	55	Chief Executive Officer, ComEd	2021 - Present
		President and Chief Executive Officer, New York Power Authority	2011 - 2021
Donnelly, Terence R.	61	President and Chief Operating Officer, ComEd	2018 - Present
		Executive Vice President and Chief Operating Officer, ComEd	2012 - 2018
Trpik, Joseph	52	Interim Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2021 - Present
		Senior Vice President, Chief Financial Officer, Exelon Utilities	2018 - Present
		Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2009 - 2018
Rippie, E. Glenn	61	Senior Vice President and General Counsel, ComEd	2022 - Present
		Partner, Jenner & Block LLP	2019 - 2021
		Partner and Chief Financial Officer, Rooney, Rippie & Ratnaswamy, LLP	2010 - 2019
Washington, Melissa	52	Senior Vice President, Customer Operations and Chief Customer Officer, ComEd	2021 - Present
		Senior Vice President, Governmental and External Affairs, ComEd	2019 - 2021
		Vice President, Governmental and External Affairs, ComEd	2019 -2019
		Vice President, External Affairs and Large Customer Services, ComEd	2016 - 2019
Perez, David	52	Senior Vice President, Distribution Operations, ComEd	2019 - Present
		Vice President, Transmission and Substation, ComEd	2016 - 2019
Blaise, M. Michelle	60	Senior Vice President, Technical Services, ComEd	2014 - Present

PECO

Name	Age	Position	Period
Innocenzo, Michael A.	56	President and Chief Executive Officer, PECO	2018 - Present
		Senior Vice President and Chief Operations Officer, PECO	2012 - 2018
McDonald, John	64	Senior Vice President and Chief Operations Officer, PECO	2018 - Present
		Vice President, Integration, PHI	2016 - 2018
Stefani, Robert J.	48	Senior Vice President, Chief Financial Officer and Treasurer, PECO	2018 - Present
		Vice President, Corporate Development, Exelon	2015 - 2018
Murphy, Elizabeth A.	62	Senior Vice President, Governmental and External Affairs, PECO	2016 - Present
Webster Jr., Richard G.	60	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
Williamson, Olufunmilayo	43	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	56	Vice President and General Counsel, PECO	2019 - Present
		Vice President, Governmental and External Affairs, PECO	2016 - 2019

BGE

Name	Age	Position	Period
Khouzami, Carim V.	46	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
Dickens, Derrick	56	Senior Vice President and Chief Operating Officer, BGE	2021 - Present
		Senior Vice President, Customer Operations, PHI	2020 - 2021
		Vice President, Technical Services, BGE	2016 - 2020
Vahos, David M.	49	Senior Vice President, Chief Financial Officer and Treasurer, BGE	2016 - Present
Núñez, Alexander G.	50	Senior Vice President, Governmental, External and Regulatory Affairs, BGE	2021 - Present
		Senior Vice President, Regulatory Affairs and Strategy, BGE	2020 - 2021
		Senior Vice President, Regulatory and External Affairs, BGE	2016 - 2020
Case, Mark D.	60	Vice President, Strategy and Regulatory Affairs, BGE	2012 - Present
Galambos, Denise	59	Senior Vice President, Customer Operations, BGE	2021 - Present
		Vice President, Utility Oversight, Exelon Utilities	2020 - 2021
		VP, Human Resources, BGE	2018 - 2020
		Associate General Counsel, Exelon	2012 - 2017
Ralph, David	55	Vice President and General Counsel, BGE	2021 - Present
		Associate General Counsel, BGE	2019 - 2021
		Assistant General Counsel, Exelon	2017 - 2019
		City Attorney, City of Baltimore	2016 - 2017

PHI, Pepco, DPL, and ACE

Name	Age	Position	Period
Anthony, J. Tyler	57	President and Chief Executive Officer, PHI	2021 - Present
		Senior Vice President and Chief Operating Officer, PHI, Pepco, DPL, and ACE	2016 - 2021
Olivier, Tamla	49	Senior Vice President and Chief Operating Officer, PHI, Pepco, DPL, and ACE	2021 - Present
		Senior Vice President, Customer Operations, BGE	2020 - 2021
		Senior Vice President, Constellation NewEnergy, Inc.	2016 - 2020
Barnett, Phillip S.	58	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
Oddoye, Rodney	45	Senior Vice President, Governmental & External Affairs, PHI, Pepco, DPL, and ACE	2021 - Present
		Senior Vice President, Governmental and External Affairs, BGE	2020 - 2021
		Vice President, Customer Operations, BGE	2018 - 2020
		Director, Northeast Regional Electric Operations, BGE	2016 - 2018
Bancroft, Anne	55	Vice President and General Counsel, PHI	2021 - Present
		Associate General Counsel, Exelon	2017 - 2021
		Assistant General Counsel, Exelon	2010 - 2017
Bell-Izzard, Morlon	56	Senior Vice President, Customer Operations & Chief Customer Officer, PHI	2021 - Present
		Vice President, Customer Operations, PHI	2019 - 2021
		Director, Utility Performance Assessment, Exelon	2016 - 2019
O'Donnell, Morgan	46	Vice President, Regulatory Policy and Strategy, DC/MD	2021 - Present
		Director, Financial Planning and Analysis, PHI	2020 - 2021
		Director, Regulatory Strategy & Revenue Policy, PHI	2019 - 2020
		Manager, Regulatory Analysis, PHI	2016 - 2019
Humphrey, Marissa	42	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

On February 21, 2021, Exelon's Board of Directors approved a plan to separate the Utility Registrants and Generation, creating two publicly traded companies. The separation was completed on February 1, 2022. See Note 26 — Separation of the Combined Notes to Consolidated Financial Statements for additional information. As such, the risk factors discussed below do not include those associated with Generation.

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:

Risks related to market and financial factors primarily include:

- the demand for electricity, reliability of service, and affordability in the markets where the Utility Registrants conduct their business,
- the ability of the Utility Registrants to operate their respective 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), and
- emerging technologies and business models, including those related to climate change mitigation and transition to a low carbon economy.

Risks related to legislative, regulatory, and legal factors primarily include changes to, and compliance with, the laws and regulations that govern:

- utility regulatory business models,
- environmental and climate policy, and
- tax policy.

Risks related to 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 ability of the Utility Registrants to maintain the reliability, resiliency, and safety of their energy delivery systems, which could affect their ability to deliver energy to their customers and affect their operating costs, and
- physical and cyber security risks for the Utility Registrants as the owner-operators of transmission and distribution facilities.

Risks related to the separation primarily include:

- challenges to achieving the benefits of separation and
- performance by Exelon and Generation under the transaction agreements, including indemnification responsibilities.

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

Risks Related to Market and Financial Factors

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

Advancements in power generation technology, including commercial and residential solar generation installations and commercial micro turbine installations, are improving the cost-effectiveness of customer self-supply of electricity. Improvements in energy storage technology, including batteries and fuel cells, could also better position customers to meet their around-the-clock electricity requirements. Improvements in energy efficiency of lighting, appliances, equipment and building materials will also affect energy consumption by customers. Changes in power generation, storage, and use technologies could have significant effects on customer behaviors and their energy consumption.

These developments could affect levels of customer-owned generation, customer expectations, and current business models and make portions of the Utility Registrants' transmission and/or distribution facilities uneconomic prior to the end of their useful lives. These factors could affect the Registrants' consolidated financial statements through, among other things, increased operating and maintenance expenses, increased capital expenditures, and potential asset impairment charges or accelerated depreciation over shortened remaining asset useful lives.

Market performance and other factors could decrease the value of 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 Exelon’s employee benefit plan trusts. The asset values are subject to market fluctuations and will yield uncertain returns, which could fall below Exelon's projected return rates. 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 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 (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, or require 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, 2021, approximately 20%, 17%, and 16% of the Registrants’ available credit facilities (not including Generation's 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.

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 or regulatory financial requirements, it would be required to provide significant amounts of collateral that could affect its liquidity and could experience higher borrowing costs (All Registrants).

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.

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 and the related regulatory limitations on residential service terminations for the Utility Registrants, could result in an increase in the number of uncollectible customer balances and related expense. 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.

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

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

COVID-19 has disrupted economic activity in the Registrants’ respective markets and negatively affected the Registrants’ results of operations. The estimated impact of COVID-19 to the Utility Registrants’ Net income was approximately $75 million for the year ended December 31, 2020 and was not material for the year ended December 31, 2021. The Registrants cannot predict the full extent of the impacts of COVID-19, which will depend on, among other things, the rate, and public perceptions of the effectiveness, of vaccinations and rate of resumption of business activity. In addition, any future widespread pandemic or other local or global health issue could adversely affect customer demand and the Registrants’ ability to operate their transmission and distribution assets. 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 operating revenues at PECO and DPL Delaware. Due to revenue decoupling, operating revenues from electric distribution at ComEd, BGE, Pepco, DPL Maryland, and ACE are not affected by abnormal weather.

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.

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 the Utility Registrants have 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 (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, including several of the Utility Registrants in connection with Generation's absorption of their former generating assets. The Registrants 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.

Risks Related to Legislative, Regulatory, and Legal Factors

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

Substantial aspects of the Registrants' businesses are subject to comprehensive Federal or state legislation and/or regulation.

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 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 or regulatory proposals could become law or what their effect would 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 (All 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.

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 Utility Registrants as users, owners, and operators of the bulk power transmission system 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, DEPSC, and NJBPU impose certain distribution reliability standards on the Utility Registrants. If the Utility Registrants were found in non-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 Registrants 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 Matters and Regulation 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 the Utility Registrants, especially if timely cost recovery is not allowed.

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. These energy conservation programs, regulated energy consumption reduction targets, and new energy consumption technologies could cause declines in customer energy consumption and lead to a decline in the Registrants' revenues. See ITEM 1. BUSINESS — Environmental Matters and Regulation — Renewable and Clean Energy Standards and "The Registrants are potentially affected by emerging technologies that could over time affect or transform the energy industry" above 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.

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.

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 in a favorable light, and could cause those companies, including the Registrants, to be susceptible to less favorable legislative and regulatory outcomes, as well as increased regulatory oversight and more stringent legislative or regulatory requirements.

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.

Risks Related to Operational Factors

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

Climate adaptation risk refers to risks to the Registrants' facilities or operations that may result from changes in the physical climate, such as changes to temperature, weather patterns and sea level.

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, and as such 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, and result in more intense, frequent and extreme weather events, unprecedented levels of precipitation, sea level rise, increased surface water temperatures, and/or other effects.

Over time, the Registrants may need to make additional investments to protect their facilities from physical climate-related risks.

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 adapt to changes in operational requirements as a result of climate change.

Climate mitigation and transition risks include changes to the energy systems as a result of new technologies, changing customer expectations and/or voluntary GHG goals, as well as local, state or federal regulatory requirements intended to reduce GHG emissions.

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 legislation and/or regulation 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. See ITEM 1. BUSINESS — Environmental Matters and Regulation — Climate Change and "The Registrants are potentially affected by emerging technologies that could over time affect or transform the energy industry" above 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 (All 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, grid infrastructure, and other energy infrastructures, and these 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 Registrants' physical assets or information systems or those of the Registrants 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 have directly experienced a material breach or disruption to its network or information systems or our 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 Registrants' reputation 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 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, ability to raise capital and future growth (All Registrants).

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 Utility 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.

The impact that potential terrorist attacks could have on the industry and the Registrants 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 the Registrants' facilities, which could adversely affect the Registrants' ability to manage their businesses 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 transmission and distribution assets could be adversely affected. See "The Registrants' results were negatively affected by the impacts of COVID-19" above for additional information.

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 Utility Registrants’ businesses are capital intensive and require significant investments 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 Utility 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 (All 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.

PJM’s 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' performance could be negatively affected if they fail to attract and retain an appropriately qualified workforce (All Registrants).

Certain events, such as the separation transaction, an employee strike, loss of employees, 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 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).

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.

Risks Related to the Separation (Exelon)

The separation may not achieve some or all of the benefits anticipated by Exelon and, following the separation, Exelon's common stock price may underperform relative to Exelon's expectations.

By separating the Utility Registrants and Generation, Exelon created 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 separation may not provide such results on the scope or scale that Exelon anticipates, and Exelon may not realize the anticipated benefits of the separation. Failure to do so could have a material adverse effect on Exelon's financial statements and its common stock price.

In connection with the separation into two public companies, Exelon and Generation will indemnify each other for certain liabilities. If Exelon is required to pay under these indemnities to Generation, Exelon's financial results could be negatively impacted. The Generation indemnities may not be sufficient to hold Exelon harmless from the full amount of liabilities for which Generation will be allocated responsibility, and Generation may not be able to satisfy its indemnification obligations in the future.

Pursuant to the separation agreement and certain other agreements between Exelon and Generation, each party will agree to indemnify the other for certain liabilities, in each case for uncapped amounts. Indemnities that Exelon may be required to provide Generation are not subject to any cap, may be significant and could negatively impact its business. Third parties could also seek to hold Exelon responsible for any of the liabilities that Generation has agreed to retain. Any amounts Exelon is required to pay pursuant to these indemnification obligations and other liabilities could require Exelon to divert cash that would otherwise have been used in furtherance of its operating business. Further, the indemnities from Generation for Exelon's benefit may not be sufficient to protect Exelon against the full amount of such liabilities, and Generation may not be able to fully satisfy its indemnification obligations.

Moreover, even if Exelon ultimately succeeds in recovering from Generation any amounts for which Exelon is held liable, Exelon may be temporarily required to bear these losses. Each of these risks could negatively affect Exelon's business, results of operations and financial condition.

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, 2021:

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)
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	(h)
Clinton Battery Storage	Blanchester, OH	1			Energy Storage	Peaking	10	
Total Midwest							11,898	
Mid-Atlantic								
Limerick	Sanatoga, PA	2			Uranium	Base-load	2,317	
Calvert Cliffs	Lusby, MD	2			Uranium	Base-load	1,789	
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)
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	
Fourmile Ridge	Garrett County, MD	16	51	(g)	Wind	Intermittent	20	(f)
Solar Horizons	Emmitsburg, MD	1	51	(g)	Solar	Intermittent	16	(f)
Solar New Jersey 3	Middle Township, NJ	4	51	(g)	Solar	Intermittent	2	(f)
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	

Station (a)	Location	No. of Units	Percent Owned (b)	Primary Fuel Type	Primary Dispatch Type (c)	Net Generation Capacity (MW) (d)
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						10,508
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)
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						3,610
New York						
Nine Mile Point	Scriba, NY	2	(i)	Uranium	Base-load	1,675 (f)
FitzPatrick	Scriba, NY	1		Uranium	Base-load	842
Ginna	Ontario, NY	1		Uranium	Base-load	576
Total New York						3,093
Other						
Antelope Valley	Lancaster, CA	1		Solar	Intermittent	242
Bluestem	Beaver County, OK	60	51 (g)(j)	Wind	Intermittent	101 (f)
Shooting Star	Kiowa County, KS	65	51 (g)	Wind	Intermittent	53 (f)
Sacramento PV Energy	Sacramento, CA	4	51 (g)	Solar	Intermittent	30 (f)
Bluegrass Ridge	King City, MO	27	51 (g)	Wind	Intermittent	29 (f)

Station[a]	Location	No. of Units	Percent Owned[b]		Primary Fuel Type	Primary Dispatch Type[c]	Net Generation Capacity (MW)[d]	
Conception	Barnard, MO	24	51	(g)	Wind	Intermittent	26	(f)
Cow Branch	Rock Port, MO	24	51	(g)	Wind	Intermittent	26	(f)
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)
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)
Tuana Springs	Hagerman, ID	8	51	(g)	Wind	Intermittent	9	(f)
Greensburg	Greensburg, KS	10	51	(g)	Wind	Intermittent	6	(f)
Echo 3	Echo, OR	6	50.49	(g)	Wind	Intermittent	5	(f)
Three Mile Canyon	Boardman, OR	6	51	(g)	Wind	Intermittent	5	(f)
Loess Hills	Rock Port, MO	4			Wind	Intermittent	5	
Denver Airport Solar	Denver, CO	1	51	(g)	Solar	Intermittent	4	(f)
Mystic 8, 9	Charlestown, MA	6			Gas	Intermediate	1,417	(e)
Hillabee	Alexander City, AL	3			Gas	Intermediate	753	
Wyman 4	Yarmouth, ME	1	5.9		Oil	Intermediate	34	(f)
West Medway II	West Medway, MA	2			Oil/Gas	Peaking	189	
West Medway	West Medway, MA	3			Oil	Peaking	124	
Grand Prairie	Alberta, Canada	1			Gas	Peaking	105	
Framingham	Framingham, MA	3			Oil	Peaking	31	
Total Other							3,291	
Total							32,400	

(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) On August 9, 2020, Generation announced it would permanently cease generation operations at Byron and Dresden nuclear facilities in 2021 and Mystic Unit 8 and 9 in 2024. On September 15, 2021, Generation reversed its previous decision to retire Byron and Dresden. 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 CRP to a third party. See Note 23 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information.

(h) Generation has deactivated the site and is evaluating for potential return of service or retirement beyond 2023.

(i) Generation wholly owns Nine Mile Point Unit 1 and has an 82% undivided ownership interest in Nine Mile Point Unit 2.

(j) CRP 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.

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 — Generation. 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 on 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, 2021 were as follows:

Voltage	Circuit Miles					
(Volts)	ComEd	PECO	BGE	Pepco	DPL	ACE
765,000	90	—	—	—	—	—
500,000[(a)]	—	188	216	109	16	—
345,000	2,676	—	—	—	—	—
230,000	—	550	358	770	472	274
138,000	2,246	135	55	61	586	214
115,000	—	—	700	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 of the Combined Notes to the Consolidated Financial Statements 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	35,387	12,981	9,164	4,127	6,006	7,364
Underground	32,498	9,555	17,796	7,162	6,427	2,951

Gas

The following table presents PECO's, BGE's, and DPL's natural gas pipeline miles at December 31, 2021:

	PECO	BGE	DPL
Transmission[(a)]	9	152	8
Distribution	6,956	7,482	2,166
Service piping	6,479	6,407	1,473
Total	13,444	14,041	3,647

(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

Not Applicable

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

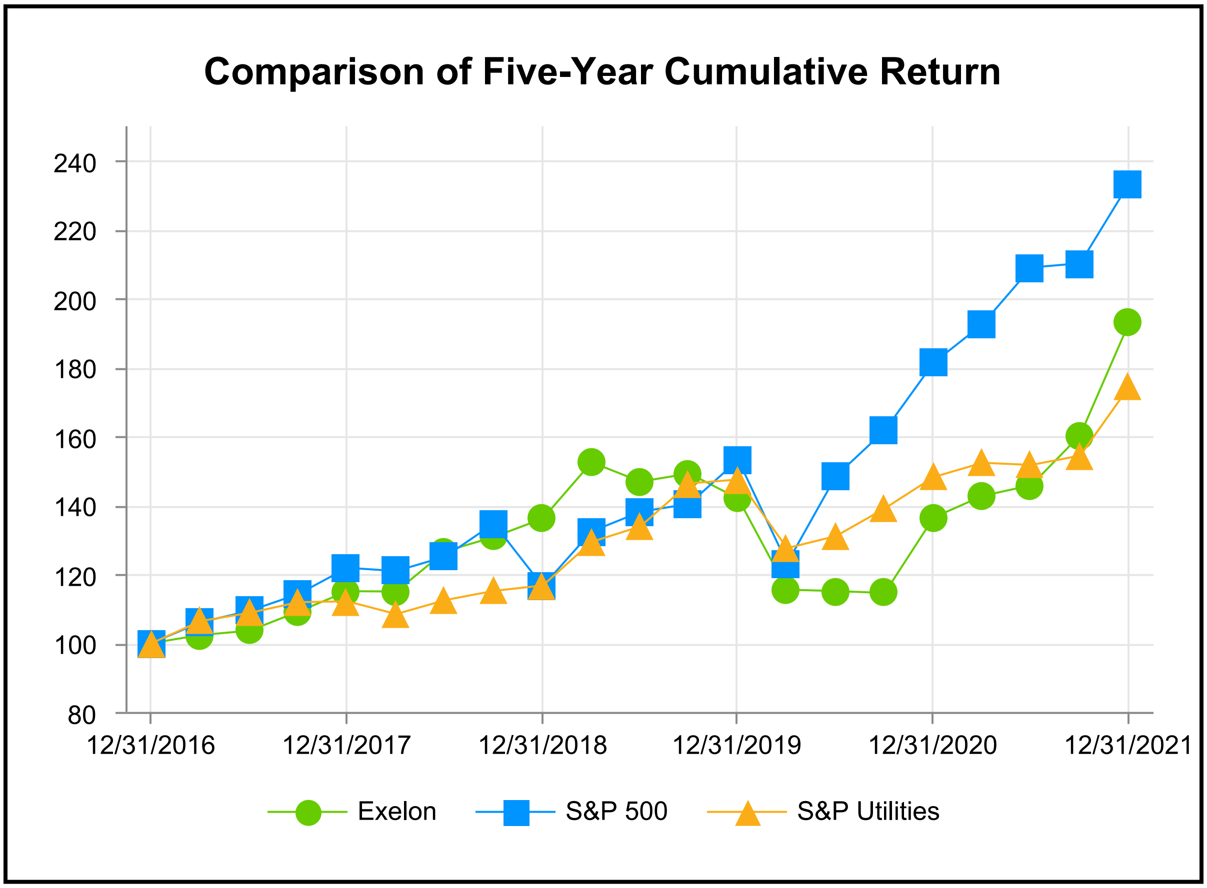
Exelon’s common stock is listed on the Nasdaq (trading symbol: EXC). As of January 31, 2022, there were 980,136,968 shares of common stock outstanding and approximately 85,423 record holders of common stock.

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 2017 through 2021.

This performance chart assumes:

- $100 invested on December 31, 2016 in Exelon common stock, the S&P 500 Stock Index, and the S&P Utility Index; and
- All dividends are reinvested.



	Value of Investment at December 31,					
	2016	2017	2018	2019	2020	2021
Exelon Corporation	$100	$115.05	$136.13	$141.96	$136.44	$192.94
S&P 500	$100	$121.83	$116.49	$153.17	$181.35	$233.41
S&P Utilities	$100	$112.11	$116.71	$147.46	$148.18	$174.36

ComEd

As of January 31, 2022, there were 127,021,391 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, 2022, in addition to Exelon, there were 285 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

PECO

As of January 31, 2022, 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, 2022, 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, 2022, Exelon indirectly held the entire membership interest in PHI.

Pepco

As of January 31, 2022, 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, 2022, 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, 2022, 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, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at, 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 DEPSC 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 2022. The 2022 quarterly dividend will be $0.3375 per share.

At December 31, 2021, Exelon had retained earnings of $16,942 million, ComEd's retained earnings of $1,691 million consisting of retained earnings appropriated for future dividends of $3,330 million, partially offset by $1,639 million of unappropriated accumulated deficits, PECO's retained earnings of $1,684 million, BGE's retained earnings of $1,995 million, and PHI's undistributed losses of $210 million.

The following table sets forth Exelon's quarterly cash dividends per share paid during 2021 and 2020:

	2021				2020			
(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	$ 0.3825	$ 0.3825	$ 0.3825	$ 0.3825

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

	2021				2020			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
ComEd	127	127	126	127	126	124	124	125
PECO	85	85	84	85	85	85	85	85
BGE	73	73	72	74	60	62	62	62
PHI	98	191	333	81	102	183	134	134
Pepco	47	98	95	28	58	73	73	28
DPL	41	43	23	40	42	33	14	52
ACE	8	51	215	14	3	76	12	23

First Quarter 2022 Dividend

On February 8, 2022, Exelon's Board of Directors declared a regular quarterly dividend of $0.3375 per share on Exelon’s common stock for the first quarter of 2022. The dividend is payable on Monday, March 10, 2022, to shareholders of record of Exelon as of 5 p.m. Eastern time on Friday, February 25, 2022.

ITEM 6. SELECTED FINANCIAL DATA

Not Applicable

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

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

Exelon

Executive Overview

As of December 31, 2021, Exelon was 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 seven separate operating subsidiary registrants, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE and its subsidiary Generation. The following combined Management’s Discussion and Analysis of Financial Condition and Results of Operations summarizes results for the year ended December 31, 2021 compared to the year ended December 31, 2020, and is separately filed by Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants. For discussion of the year ended December 31, 2020 compared to the year ended December 31, 2019, refer to ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS in the 2020 Form 10-K, which was filed with the SEC on February 24, 2021.

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 by taking extra precautions for employees who work in the field and in our facilities. The Registrants have implemented work from home policies where appropriate, and imposed travel limitations on employees.

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 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 resulted in an estimated reduction to Exelon’s Net income of approximately $245 million for the year ended December 31, 2020. The impact was not material for the year ended December 31, 2021. To offset the unfavorable impacts from COVID-19, Exelon identified approximately $250 million in cost savings in 2020. The cost savings achieved in 2020 were higher than originally anticipated.

The Registrants assessed long-lived assets, goodwill, and investments for recoverability and there were no material impairment charges recorded in 2020 or 2021 as a result of COVID-19. See Note 12 — Asset Impairments of the Combined Notes to Consolidated Financial Statements for additional information related to other impairment assessments.

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 Registrants cannot predict the full extent of the impacts of COVID-19, which will depend on, among other things, the rate, and public perceptions of the effectiveness, of vaccinations and rate of resumption of business activity.

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 or subsidiary for the year ended December 31, 2021 compared to the same period in 2020. For additional information regarding the financial results for the years ended December 31, 2021 and 2020 see the discussions of Results of Operations by Registrant or subsidiary.

	2021	2020	(Unfavorable) Favorable Variance
Exelon	$ 1,706	$ 1,963	$ (257)
ComEd	742	438	304
PECO	504	447	57
BGE	408	349	59
PHI	561	495	66
Pepco	296	266	30
DPL	128	125	3
ACE	146	112	34
Generation	(205)	589	(794)
Other[a]	(304)	(355)	51

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

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020. **Net income attributable to common shareholders** decreased by $257 million and diluted earnings per average common share decreased to $1.74 in 2021 from $2.01 in 2020 primarily due to:

- Impacts of the February 2021 extreme cold weather event;
- Accelerated depreciation and amortization associated with Generation's previous decision in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021, a decision which was reversed on September 15, 2021, and Generation's decision in the third quarter of 2020 to early retire Mystic Units 8 and 9 in 2024;
- Decommissioning-related activities that were not offset for the Byron units beginning in the second quarter of 2021 through September 15, 2021. With Generation's September 15, 2021 reversal of the previous decision to retire Byron, Generation resumed contractual offset for Byron as of that date;
- Impairments at Generation of the New England asset group, the Albany Green Energy biomass facility, and a wind project, partially offset by the absence of an impairment of the New England asset group in the third quarter of 2020;
- Higher net unrealized and realized losses on equity investments; and
- The absence of prior year one-time tax settlements.

The decreases were partially offset by;

- Higher electric distribution earnings from higher rate base and higher allowed ROE due to an increase in treasury rates at ComEd;
- The favorable impacts of the multi-year plan at BGE and Pepco and regulatory rate increases at DPL and ACE;
- Favorable weather conditions at PECO and DPL's Delaware service territory;
- Favorable volume at PECO and ACE;
- Lower storm costs at PECO and DPL due to the absence of the June 2020 and August 2020 storms, respectively;
- Lower operating and maintenance expense at ComEd due to the payments that ComEd made in 2020 under the Deferred Prosecution Agreement;
- Higher mark-to-market gains;
- Higher net unrealized and realized gains on NDT funds;
- Absence of one time charges recorded in the third quarter of 2020 associated with Generation's decision to early retire the Byron and Dresden nuclear facilities and Mystic Units 8 and 9, and the reversal of one-time charges resulting from the reversal of the previous decision to early retire Byron and Dresden on September 15, 2021;
- Favorable sales and hedges of excess emission credits;
- Favorable commodity prices on fuel hedges;
- Lower nuclear fuel costs due to accelerated amortization of nuclear fuel and lower prices; and
- Higher New York ZEC revenues due to higher generation and an increase in ZEC prices.

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, 2021 as compared to 2020:

	For the Years Ended December 31,			
	2021		2020	
(In millions, except per share data)		**Earnings per Diluted Share**		**Earnings per Diluted Share**
Net Income Attributable to Common Shareholders	**$ 1,706**	**$ 1.74**	**$ 1,963**	**$ 2.01**
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $145 and $73, respectively)	(421)	(0.43)	(213)	(0.22)
Unrealized Gains Related to NDT Fund Investments (net of taxes of $141 and $278, respectively)[a]	(139)	(0.14)	(256)	(0.26)
Asset Impairments (net of taxes of $136 and $135, respectively)[b]	405	0.41	396	0.41
Plant Retirements and Divestitures (net of taxes of $290 and $244, respectively)[c]	865	0.88	718	0.74
Cost Management Program (net of taxes of $2 and $14, respectively)[d]	9	0.01	45	0.05
Asset Retirement Obligation (net of taxes of $12 and $16, respectively)[e]	(35)	(0.04)	48	0.05
Change in Environmental Liabilities (net of taxes of $3 and $6, respectively)	9	0.01	18	0.02
COVID-19 Direct Costs (net of taxes of $13 and $19, respectively)[f]	36	0.04	50	0.05
Deferred Prosecution Agreement Payments (net of taxes of $0)[g]	—	—	200	0.20
Acquisition Related Costs (net of taxes of $5 and $1, respectively)[h]	15	0.02	4	—
ERP System Implementation Costs (net of taxes of $4 and $1, respectively)[i]	13	0.01	3	—
Separation Costs (net of taxes of $31)[j]	90	0.09	—	—
Costs Related to Suspension of Contractual Offset (net of taxes of $45)[k]	148	0.15	—	—
Income Tax-Related Adjustments (entire amount represents tax expense)[l]	47	0.05	71	0.07
Noncontrolling Interests (net of taxes of $2 and $19, respectively)[m]	16	0.02	103	0.11
Adjusted (non-GAAP) Operating Earnings	**$ 2,764**	**$ 2.82**	**$ 3,149**	**$ 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 2021 and 2020 ranged from 25.0% to 29.0%. Under IRS regulations, NDT fund investment returns are taxed at different rates for investments if they are in qualified or non-qualified funds. The effective tax rates for the unrealized gains and losses related to NDT funds were 50.4% and 52.1% for the years ended December 31, 2021 and 2020, respectively.

(a) Reflects the impact of net unrealized gains and losses on Generation’s NDT fund investments for Non-Regulatory Agreement Units.

(b) In 2021, reflects an impairment of the New England asset group, an impairment recorded as a result of the agreement to sell the Albany Green Energy biomass facility, and an impairment of a wind project at Generation. In 2020, reflects an impairment at ComEd related to the acquisition of transmission assets and an impairment of the New England asset group in the third quarter of 2020 at Generation.

(c) In 2021, primarily reflects accelerated depreciation and amortization associated with Generation's decisions to early retire Byron, Dresden, and Mystic Units 8 and 9, partially offset by reversal of one-time charges resulting from the reversal of the previous decision to retire Byron and Dresden on September 15, 2021 and a gain on sale of Generation's solar business. Depreciation for Byron and Dresden was adjusted beginning September 15, 2021 to reflect the extended useful life estimates. In 2020, primarily reflects one-time charges and accelerated depreciation and amortization expenses 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.

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

(e) For Generation, reflects an adjustment to the nuclear asset obligation for the Non-Regulatory Agreement Units resulting from the annual update in the third quarter of 2021 and fourth quarter of 2020, respectively.

(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 in July 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, which was completed in the third quarter of 2021.

(i) Reflects costs related to a multi-year Enterprise Resource Program (ERP) system implementation.

(j) Represents costs related to the separation primarily comprised of system-related costs, third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the planned separation, and employee-related severance costs.

(k) Decommissioning-related activities for the former ComEd and PECO units (Regulatory Agreement Units), 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 consolidated statements of operations. These costs reflect the impact of suspension of contractual offset for the Byron units beginning in the second quarter of 2021 through September 15, 2021. With Generation's September 15, 2021 reversal of the previous decision to retire Byron, Generation resumed contractual offset for Byron as of that date.

(l) In 2021, primarily reflects the recognition of a valuation allowance against a deferred tax asset associated with Delaware net operating loss carryforwards due to a change in Delaware tax law. In 2021 and 2020, also reflects the adjustment to deferred income taxes due to changes in forecasted apportionment.

(m) Represents elimination from Generation’s results of the noncontrolling interests related to certain exclusion items, primarily related to unrealized gains and losses on NDT fund investments for CENG units prior to Generation's acquisition of EDF's interest in CENG on August 6, 2021 and the noncontrolling interest portion of a wind project impairment.

Significant 2021 Transactions and Developments

Separation

On February 21, 2021, Exelon’s Board of Directors approved a plan to separate the Utility Registrants and Generation, creating two publicly traded companies with the resources necessary to best serve customers and sustain long-term investment and operating excellence ("the separation"). The separation gives each company the financial and strategic independence to focus on its specific customer needs, while executing its core business strategy. Exelon completed the separation on February 1, 2022. The new publicly traded company is Constellation Energy Corporation. See Note 26 — Separation of the Combined Notes to Consolidated Financial Statements for additional information.

In connection with the separation, Exelon incurred transaction costs of $122 million on a pre-tax basis for the year ended December 31, 2021, which are recorded in Operating and maintenance expense. Exelon expects to incur incremental transaction costs of approximately $90 million in 2022. These costs are excluded from Adjusted (non-GAAP) Operating Earnings. The transaction costs are primarily comprised of system-related costs, third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the separation, and employee-related severance costs.

CENG Put Option

EDF had 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 and sell its 49.99% equity interest in CENG to Generation and the put automatically exercised on January 19, 2020 at the end of the sixty-day advance notice period. On August 6, 2021, Generation and EDF entered into a settlement agreement pursuant to which Generation, through a wholly owned subsidiary, purchased EDF’s equity interest in CENG for a net purchase price of $885 million, which includes, among other things, an adjustment for EDF’s share of the balance of the preferred distribution payable by CENG to Generation. The difference between the net purchase price and EDF’s noncontrolling interest as of the closing date was recorded to Common Stock in Exelon’s Consolidated Balance Sheet.

In connection with the settlement agreement, on August 6, 2021, Generation issued approximately $880 million under a term loan credit agreement to fund the transaction, which will expire on August 5, 2022.

See Note Note 2 — Mergers, Acquisitions, and Dispositions and Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

Clean Energy Law

On September 15, 2021, the Illinois Public Act 102-0662 was signed into law by the Governor of Illinois ("Clean Energy Law"). The Clean Energy Law is designed to achieve 100% carbon-free power by 2045 to enable the state's transition to a clean energy economy. The Clean Energy Law establishes decarbonization requirements for Illinois as well as programs to support the retention and development of emissions-free sources of electricity. Among other things, the Clean Energy Law authorized the IPA to procure up to 54.5 million CMCs from qualifying nuclear plants for a five-year period beginning on June 1, 2022 through May 31, 2027. CMCs are credits for the carbon-free attributes of eligible nuclear power plants in PJM. The Byron, Dresden, and Braidwood nuclear plants located in Illinois participated in the CMC procurement process and were awarded contracts that commit each plant to operate through May 31, 2027. Pursuant to these contracts, ComEd will procure CMCs based upon the number of MWhs produced annually by each plant, subject to minimum performance requirements. ComEd is required to purchase CMCs pursuant to these contracts and all its costs of doing so will be recovered through a new rider.

Following enactment of the Clean Energy Law, Generation announced on September 15, 2021, that it has reversed the previous decision to retire Byron and Dresden given the opportunity for additional revenue. In addition, Generation no longer considers the Braidwood or LaSalle nuclear plants to be at risk for premature retirement. See Note 7 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information and Early Retirement of Generation Facilities below.

The Clean Energy Law also contains requirements associated with ComEd's transition away from the performance-based electric distribution formula rate. The law authorizing that rate setting process sunsets at the end of 2022. The Clean Energy Law, and tariffs adopted under it, governs both the remaining reconciliations of rates set under that process and requires ComEd to file in 2023 its choice of either a general rate case or a four-year multi-year plan to set rates that take effect in 2024. If ComEd elects to file a multi-year plan, that plan would set rates for 2024 – 2027, based on forecasted revenue requirements and an ICC determined rate of return on rate base, including the cost of common equity. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information and other features of the Clean Energy Law.

Early Retirement of Generation Facilities

In August 2020, Generation announced the intention 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, Exelon recognized a $500 million pre-tax impairment for the New England asset group along with certain one-time charges in the third and fourth quarters of 2020 in addition to 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.

In the second quarter of 2021, an incremental decline in value resulted in an additional pre-tax impairment charge of $350 million for the New England asset group.

Exelon recorded pre-tax charges of $53 million and $140 million, in the second and third quarters of 2021, respectively, for decommissioning-related activities that were not offset for the Byron units due to the inability to recognize a regulatory asset at ComEd.

On September 15, 2021, Generation reversed the previous decision to early retire Byron and Dresden and the expected economic useful life for both facilities was updated to 2044 and 2046 for Byron Units 1 and 2, respectively, and to 2029 and 2031 for Dresden Units 2 and 3, respectively. Depreciation was therefore adjusted beginning September 15, 2021, to reflect these extended useful life estimates. In addition, in the third quarter of 2021, Exelon reversed approximately $81 million of severance benefit costs and $13 million of other one-time charges initially recorded in the third and fourth quarters of 2020 associated with the early retirements.

All of the charges were excluded from Exelon's Adjusted (non-GAAP) Operating Earnings.

Exelon recognized pre-tax expenses for Byron, Dresden, and Mystic Units 8 and 9 of $1,458 million for the year ended December 31, 2021, primarily due to accelerated depreciation and amortization of plant assets, partially offset by the reversal of one-time charges for Byron and Dresden.

See Note 7 — Early Plant Retirements, Note 10 — Asset Retirement Obligations, and Note 12 — Asset Impairments of the Combined Notes to Consolidated Financial Statements for additional information.

Impacts of the February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages

Beginning on February 15, 2021, Generation's Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced outages as a result of extreme cold weather conditions. In addition, those weather conditions drove increased demand for service, dramatically increased wholesale power prices, and also increased gas prices in certain regions.

The estimated impact to Exelon's Net income for the year ended December 31, 2021 arising from these market and weather conditions was a reduction of approximately $800 million. The ultimate impact to Exelon's consolidated financial statements may be affected by a number of factors, including the impacts of customer and counterparty defaults and recoveries, any additional solutions to address the financial challenges caused by the event, and related litigation and contract disputes. See Note 3 — Regulatory Matters and Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

To offset a portion of the unfavorable impacts, Exelon identified between $410 million and $490 million of enhanced revenue opportunities, deferral of selected non-essential maintenance, and primarily one-time cost savings, primarily at Generation, which was achieved in 2021.

Agreement for the Sale of a Generation Biomass Facility

On April 28, 2021, Generation and ReGenerate Energy Holdings, LLC ("ReGenerate") entered into a purchase agreement, under which ReGenerate agreed to purchase Generation's interest in the Albany Green Energy biomass facility. As a result, in the second quarter of 2021, Exelon recorded a pre-tax impairment charge of $140 million which is excluded from Exelon's Adjusted (non-GAAP) Operating Earnings. The sale was completed on June 30, 2021 for a net purchase price of $36 million. Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements 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 2021. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on these and other regulatory proceedings.

Completed Distribution Base Rate Case Proceedings

Registrant/ Jurisdiction	Filing Date	Service	Requested Revenue Requirement (Decrease) Increase	Approved Revenue Requirement (Decrease) Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois	April 16, 2020	Electric	$ (11)	$ (14)	8.38 %	December 9, 2020	January 1, 2021
	April 16, 2021	Electric	51	46	7.36 %	December 1, 2021	January 1, 2022
PECO - Pennsylvania	September 30, 2020	Natural Gas	69	29	10.24 %	June 22, 2021	July 1, 2021
	March 30, 2021	Electric	246	132	N/A	November 18, 2021	January 1, 2022
BGE - Maryland	May 15, 2020 (amended September 11, 2020)	Electric	203	140	9.50 %	December 16, 2020	January 1, 2021
		Natural Gas	108	74	9.65 %		
Pepco - District of Columbia	May 30, 2019 (amended June 1, 2020)	Electric	136	109	9.275 %	June 8, 2021	July 1, 2021
Pepco - Maryland	October 26, 2020 (amended March 31, 2021)	Electric	104	52	9.55 %	June 28, 2021	June 28, 2021
DPL - Delaware	March 6, 2020 (amended February 2, 2021)	Electric	23	14	9.60 %	September 15, 2021	October 6, 2020
ACE - New Jersey	December 9, 2020 (amended February 26, 2021)	Electric	67	41	9.60 %	July 14, 2021	January 1, 2022

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
DPL - Delaware	January 14, 2022	Natural Gas	$ 14	10.30 %	First quarter of 2023
DPL - Maryland	September 1, 2021 (amended December 23, 2021)	Electric	27	10.10 %	First quarter of 2022

Transmission Formula Rates

The following total increases/(decreases) were included in the Utility Registrants' 2021 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 Increase	Total Revenue Requirement Increase	Allowed Return on Rate Base	Allowed ROE
ComEd	$ 33	$ 12	$ 45	8.20 %	11.50 %
PECO	(2)	26	24	7.37 %	10.35 %
BGE	38	27	65	7.35 %	10.50 %
Pepco	(9)	21	12	7.68 %	10.50 %
DPL	19	33	52	7.20 %	10.50 %
ACE	27	24	51	7.45 %	10.50 %

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.

Legislative and Regulatory Developments

FERC Supplemental Notice of Proposed Rulemaking

On April 15, 2021, FERC issued a Supplemental Notice of Proposed Rulemaking (NOPR) proposing to modify the current regulation permitting a continuous 50-basis-point ROE incentive adder for a transmission utility that joins and remains a member of a RTO. Under the NOPR, the ROE incentive adder would only be available for a period of up to three years after a transmission utility newly joins a RTO and all existing ROE incentive adders would end for transmission utilities that have been members for three or more years. The Utility Registrants’ existing transmission rates include the ROE incentive adder. Exelon submitted comments to FERC on this matter on June 25, 2021. Exelon cannot predict the outcome, but a final rule as proposed could have an adverse impact to the Registrants’ financial statements. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding the Utility Registrants’ transmission formula rates and regulatory proceedings at FERC.

City of Chicago Franchise Agreement

ComEd has had a Franchise Agreement with the City of Chicago (the City) since 1992. The Franchise Agreement grants rights to use the public right of way to install, maintain, and operate the wires, poles, and other infrastructure required to deliver electricity to residents and businesses across the City. The Franchise Agreement became terminable on one year notice as of December 31, 2020. It now continues in effect indefinitely unless and until either party issues a notice of termination, effective one year later, or it is replaced by mutual agreement with a new franchise agreement between ComEd and the City. If either party terminates and no new agreement is reached between the parties, the parties could continue with ComEd providing electric services within the City with no franchise agreement in place. The City also has an option to terminate and purchase the ComEd system (“municipalize”), which also requires one year notice. Neither party has issued a notice of termination at this time, the City has not exercised its municipalization option, and no new agreement has been reached. Accordingly, the 1992 Franchise Agreement remains in effect at this time. In April 2021, the City invited interested parties to respond to a Request for Information (RFI) regarding the franchise for electricity delivery. Under this process, the City could choose to terminate the ComEd Franchise Agreement on one year notice and grant a franchise to another party instead. Final responses to the RFI were due on July 30, 2021, however, on July 29, 2021, the City chose to extend the final submission deadline to September 30, 2021. ComEd submitted its response to the RFI by the due date and looks forward to continuing engagement with the City about its response. While Exelon and ComEd cannot predict the ultimate outcome of the RFI and the Franchise Agreement, fundamental changes in the agreement or other adverse actions affecting ComEd's business in the City would require changes in their business planning models and operations and could have a material adverse impact on Exelon's and ComEd's consolidated financial statements. If the City were to disconnect from the ComEd system, ComEd would seek full compensation for the business and its associated property taken by the City, as well as for all damages resulting to ComEd and its system. ComEd would also seek appropriate compensation for stranded costs with FERC.

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 on the application of these accounting policies can be found in the Combined Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations (Exelon)

Exelon recorded AROs associated with decommissioning Generation's nuclear units of $12.7 billion at December 31, 2021. 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 nuclear plant retirements in the industry, in recent years, 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 amount of NDT funds could also 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.

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 the nuclear AROs are adjusted each year for 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 generally include the following three alternatives: (1) DECON, which assumes major decommissioning activities begin shortly after the cessation of operation, (2) Shortened SAFSTOR, which generally assumes a 30-year delay prior to onset of major decommissioning activities, and (3) SAFSTOR, which assumes the nuclear facility is placed and maintained in such condition during decommissioning so that the nuclear facility can be safely stored and subsequently decontaminated 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 funds at the time of shutdown and regulatory or other commitments.

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 initial 20-year license renewal term, (3) the probability of a second, 20-year license renewal term, 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 from the industry 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 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). 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 due to 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, are measured using the average historical CARFR rates used in creating the initial ARO cost layers. If all of Generation's future nominal cash flows associated with the ARO were to be discounted at the current prevailing CARFR, the obligation would increase from approximately $12.7 billion to approximately $16.0 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:

Change in the CARFR applied to the annual ARO update	**(Decrease) Increase to ARO as of December 31, 2021**
2020 CARFR rather than the 2021 CARFR	$ (490)
2021 CARFR increased by 50 basis points	(600)
2021 CARFR decreased by 50 basis points	750

ARO Sensitivities. Changes in the assumptions underlying the ARO could materially affect the decommissioning obligation. The impact of a change in any one of these assumptions to the ARO 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:

Change in ARO Assumption		Increase to ARO as of December 31, 2021
Cost escalation studies		
Uniform increase in escalation rates of 50 basis points	$	2,900
Probabilistic cash flow models		
Increase the estimated costs to decommission the nuclear plants by 10 percent		1,110
Increase the likelihood of the DECON scenario by 10 percent and decrease the likelihood of the SAFSTOR scenario by 10 percent(a)		480
Shorten each unit's probability weighted operating life assumption by 10 percent(b)		1,570
Extend the estimated date for DOE acceptance of SNF to 2040		290

(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 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, 2021, 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 2021 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 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 difference between the fair value of the contracts at the time of acquisition and the contract value based on the terms of each contract. 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 are 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 (Exelon)

Exelon regularly monitors and 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 potential 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.

The review of long-lived assets or 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 Generation, 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. 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 Generation, 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. The cash flows from the generating units are generally evaluated at a regional portfolio level given the interdependency of cash flows generated from the customer supply and risk management activities within each region. In certain cases, the 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).

On a quarterly basis, Generation assesses its long-lived assets or asset groups for indicators of potential 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 may not be recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset 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 asset or asset groups. This includes significant assumptions of the estimated future cash flows generated by the asset or asset groups 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, 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 conducted periodically and as 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. 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-2021 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:

	Actual Assumption					
Actuarial Assumption	**Pension**	**OPEB**	**Change in Assumption**	**Pension**	**OPEB**	**Total**
Change in 2021 cost:						
Discount rate[(a)]	2.58%	2.51%	0.5%	$ (57)	$ (10)	$ (67)
	2.58%	2.51%	(0.5)%	82	11	93
EROA	7.00%	6.46%	0.5%	(95)	(12)	(107)
	7.00%	6.46%	(0.5)%	95	12	107
Change in benefit obligation at December 31, 2021:						
Discount rate[(a)]	2.92%	2.88%	0.5%	(1,393)	(242)	(1,635)
	2.92%	2.88%	(0.5)%	1,618	279	1,897

(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 (All Registrants)

For their regulated electric and gas operations, the 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, the 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 gains (losses) to be included in net income that could result from the elimination of regulatory assets and liabilities and charges against OCI related to deferred costs associated with Exelon's pension and OPEB plans that are recorded as regulatory assets in Exelon's Consolidated Balance Sheets (before taxes):

December 31, 2021	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Gain (loss)	$ 3,743	$ 4,739	$ (262)	$ 268	$ (920)	$ (182)	$ 186	$ (239)
Charge against OCI[(a)]	$ (3,259)	$ —	$ —	$ —	$ —	$ —	$ —	$ —

(a) Exelon's charge against OCI (before taxes) consists of up to $2.2 billion, $391 million, $703 million, $323 million, $154 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 $66 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 of the Registrants.

For each regulatory jurisdiction in which they conduct business, the 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 the 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 underlying 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 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 the likelihood of recovering the associated costs through customer rates.

NPNS. As part of Generation’s energy marketing business, Generation enters 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 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, 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 to enter 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 derivative pricing is verified using indicative price quotations available through brokers or over-the-counter, online exchanges. The price quotations reflect the average of the mid-point of the bid-ask spread from observable 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 predominantly 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, and both historical and current market data in its assessment of nonperformance 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, 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 to 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 Revenues, and Alternative Revenue Program Accounting 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 monthly. 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 alternative 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, DPL, and ACE 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, DCPSC, and/or NJBPU 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 (All 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, DEPSC, and NJBPU regulations.

Results of Operations by Registrant or Subsidiary

Results of Operations—ComEd

	2021	2020	Favorable (Unfavorable) Variance
Operating revenues	$ 6,406	$ 5,904	$ 502
Operating expenses			
Purchased power expense	2,271	1,998	(273)
Operating and maintenance	1,355	1,520	165
Depreciation and amortization	1,205	1,133	(72)
Taxes other than income taxes	320	299	(21)
Total operating expenses	5,151	4,950	(201)
Operating income	1,255	954	301
Other income and (deductions)			
Interest expense, net	(389)	(382)	(7)
Other, net	48	43	5
Total other income and (deductions)	(341)	(339)	(2)
Income before income taxes	914	615	299
Income taxes	172	177	5
Net income	$ 742	$ 438	$ 304

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020. **Net income** increased by $304 million primarily due to increases in electric distribution formula rate earnings (reflecting the impacts of higher rate base and higher allowed electric distribution ROE due to an increase in treasury rates) and payments that ComEd made in 2020 under the Deferred Prosecution Agreement. 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:

	2021 vs. 2020 Increase
Electric Distribution	$ 135
Energy efficiency	42
Transmission	13
Other	23
	213
Regulatory required programs	289
Total increase	$ 502

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

Distribution Revenue. EIMA and FEJA provide for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Electric distribution revenue varies from year to year based upon fluctuations in the underlying costs (e.g., severe weather and storm restoration), investments being recovered, and allowed ROE. Electric distribution revenue increased during the year ended December 31, 2021, as compared to the same period in 2020, due to the impact of higher rate base and higher allowed ROE due to an increase in treasury rates.

Energy Efficiency Revenue. FEJA provides for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Under FEJA, energy efficiency revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, and allowed ROE. Energy efficiency revenue increased during the year ended December 31, 2021, as compared to the same period in 2020, primarily due to increased regulatory asset amortization, which is fully recoverable.

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, 2021, as compared to the same period in 2020, transmission revenues increased primarily due to the impact of a higher rate base.

Other Revenue primarily includes assistance provided to other utilities through mutual assistance programs. Other revenue increased for the year ended December 31, 2021, as compared to the same period in 2020, which primarily reflects mutual assistance revenues associated with storm restoration efforts.

Regulatory Required Programs represents revenues collected under approved riders to recover costs incurred for regulatory programs such as recoveries under the credit loss expense tariff, environmental costs associated with MGP sites, 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 either acts as the billing agent or the competitive supplier separately bills its own customers, and therefore does not record Operating revenues or Purchased power expense related to the electricity. For customers that choose to purchase electric generation from ComEd, ComEd is permitted to recover the electricity, ZEC, 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 $273 million for the year ended December 31, 2021, as compared to the same period in 2020, 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:

	2021 vs. 2020
	(Decrease) Increase
Deferred Prosecution Agreement payments[(a)]	$ (200)
BSC costs	21
Labor, other benefits, contracting, and materials	(5)
Pension and non-pension postretirement benefits expense	6
Storm-related costs	(6)
Other	4
	(180)
Regulatory required programs[(b)]	15
Total decrease	$ (165)

(a) See Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

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

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

	2021 vs. 2020
	Increase
Depreciation and amortization[(a)]	$ 48
Regulatory asset amortization[(b)]	24
Total increase	$ 72

(a) Reflects ongoing capital expenditures.

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

Effective income tax rates for the years ended December 31, 2021 and 2020, were 18.8% and 28.8%, 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

	2021	2020	(Unfavorable) Favorable Variance
Operating revenues	$ 3,198	$ 3,058	$ 140
Operating expenses			
Purchased power and fuel expense	1,081	1,018	(63)
Operating and maintenance	934	975	41
Depreciation and amortization	348	347	(1)
Taxes other than income taxes	184	172	(12)
Total operating expenses	2,547	2,512	(35)
Operating income	651	546	105
Other income and (deductions)			
Interest expense, net	(161)	(147)	(14)
Other, net	26	18	8
Total other income and (deductions)	(135)	(129)	(6)
Income before income taxes	516	417	99
Income taxes	12	(30)	(42)
Net income	$ 504	$ 447	$ 57

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020. **Net income** increased by $57 million primarily due to favorable weather conditions, an increase in volume, and a decrease in storm cost activity, net of tax repair deductions.

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

	2021 vs. 2020		
	(Decrease) Increase		
	Electric	Gas	Total
Weather	$ 16	$ 1	$ 17
Volume	15	13	28
Pricing	12	7	19
Transmission	13	—	13
Other	1	3	4
	57	24	81
Regulatory required programs	58	1	59
Total increase	$ 115	$ 25	$ 140

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, 2021 compared to the same period in 2020, Operating revenues related to weather increased due to the impact of favorable weather conditions in PECO's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO’s service territory. The changes in heating and cooling degree days in PECO’s service territory for the years ended December 31, 2021 compared to the same period in 2020 and normal weather consisted of the following:

Heating and Cooling Degree-Days	For the Years Ended December 31, 2021	2020	Normal	% Change 2021 vs. 2020	2021 vs. Normal
Heating Degree-Days	3,946	3,959	4,409	(0.3)%	(10.5)%
Cooling Degree-Days	1,586	1,521	1,435	4.3 %	10.5 %

Volume. Electric volume, exclusive of the effects of weather, for the year ended December 31, 2021 compared to the same period in 2020, increased on a net basis due to an increase in overall usage for customers further increased by customer growth. Natural gas volume for the year ended December 31, 2021 compared to the same period in 2020, increased due to retail load growth.

Electric Retail Deliveries to Customers (in GWhs)	2021	2020	% Change 2021 vs. 2020	Weather - Normal % Change[b]
Retail Deliveries[a]				
Residential	14,262	14,041	1.6 %	0.1 %
Small commercial & industrial	7,597	7,210	5.4 %	4.3 %
Large commercial & industrial	14,003	13,669	2.4 %	2.1 %
Public authorities & electric railroads	559	575	(2.8)%	(2.8)%
Total electric retail deliveries	36,421	35,495	2.6 %	1.7 %

(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, 2021	2020
Residential	1,517,806	1,508,622
Small commercial & industrial	155,308	154,421
Large commercial & industrial	3,107	3,101
Public authorities & electric railroads	10,306	10,206
Total	1,686,527	1,676,350

Natural Gas Deliveries to customers (in mmcf)	2021	2020	% Change 2021 vs. 2020	Weather - Normal % Change[b]
Retail Deliveries[a]				
Residential	39,580	38,272	3.4 %	1.4 %
Small commercial & industrial	21,361	19,341	10.4 %	7.0 %
Large commercial & industrial	34	36	(5.6)%	8.3 %
Transportation	25,081	24,533	2.2 %	1.4 %
Total natural gas deliveries	86,056	82,182	4.7 %	2.8 %

(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.

Number of Gas Customers	As of December 31, 2021	2020
Residential	497,873	492,298
Small commercial & industrial	44,815	44,472
Large commercial & industrial	6	5
Transportation	670	713
Total	543,364	537,488

Pricing for the year ended December 31, 2021 compared to the same period in 2020 increased primarily due to higher overall effective rates due to favorable customer mix. 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.

Other Revenue primarily includes revenue related to late payment charges. Other revenues for the year ended December 31, 2021 compared to the same period in 2020, remained relatively consistent.

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

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

The increase of $63 million for the year ended December 31, 2021 compared to the same period in 2020, respectively, in **Purchased power and fuel expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	2021 vs. 2020 Increase (Decrease)
Storm-related costs[a]	$ (64)
Credit loss expense	(3)
Labor, other benefits, contracting, and materials	23
BSC costs	19
Pension and non-pension postretirement benefits expense	2
Other	(8)
	(31)
Regulatory Required Programs	(10)
Total decrease	$ (41)

(a) Primarily reflects the absence of costs in 2021 due to the June and August 2020 storms.

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

	2021 vs. 2020
	Increase (Decrease)
Depreciation and amortization[a]	$ 17
Regulatory asset amortization	(16)
Total increase	$ 1

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

Taxes other than income taxes increased by $12 million for the year ended December 31, 2021 compared to the same period in 2020, primarily due to higher PA gross receipts tax, which is offset in operating revenues, and PA Use Tax.

Interest expense, net increased $14 million for the year ended December 31, 2021 compared to the same period in 2020, respectively, primarily due to the issuance of debt in 2021.

Effective income tax rates were 2.3% and (7.2)% for the years ended December 31, 2021 and 2020, 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

	2021	2020	Favorable (Unfavorable) Variance
Operating revenues	$ 3,341	$ 3,098	$ 243
Operating expenses			
Purchased power and fuel	1,175	991	(184)
Operating and maintenance	811	789	(22)
Depreciation and amortization	591	550	(41)
Taxes other than income taxes	283	268	(15)
Total operating expenses	2,860	2,598	(262)
Operating income	481	500	(19)
Other income and (deductions)			
Interest expense, net	(138)	(133)	(5)
Other, net	30	23	7
Total other income and (deductions)	(108)	(110)	2
Income before income taxes	373	390	(17)
Income taxes	(35)	41	76
Net income	$ 408	$ 349	$ 59

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020. **Net income** increased by $59 million primarily due to favorable impacts of the multi-year plan, partially offset by an increase in depreciation and amortization expense. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the three-year electric and natural gas distribution multi-year plans.

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

	2021 vs. 2020		
	Increase		
	Electric	Gas	Total
Distribution	$ 7	$ 2	$ 9
Transmission	35	—	35
Other	13	3	16
	55	5	60
Regulatory required programs	116	67	183
Total increase	$ 171	$ 72	$ 243

Revenue Decoupling. The demand for electricity and natural gas is affected by weather and customer usage. However, Operating revenues are not impacted by abnormal weather or usage per customer as a result of a monthly rate adjustment that provides for fixed distribution revenue per customer by customer class. While Operating revenues are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on revenue decoupling for BGE.

	As of December 31,	
Number of Electric Customers	**2021**	**2020**
Residential	1,195,929	1,190,678
Small commercial & industrial	115,049	114,173
Large commercial & industrial	12,637	12,478
Public authorities & electric railroads	268	267
Total	1,323,883	1,317,596

	As of December 31,	
Number of Gas Customers	**2021**	**2020**
Residential	651,589	647,188
Small commercial & industrial	38,300	38,267
Large commercial & industrial	6,179	6,101
Total	696,068	691,556

Distribution Revenue increased for the year ended December 31, 2021 compared to the same period in 2020, due to customer growth.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. Transmission revenue increased for the year ended December 31, 2021 compared to the same period in 2020 primarily due to the reduction in revenue in 2020 due to the settlement agreement of ongoing transmission-related income tax regulatory liabilities and increases in underlying costs and capital investments.

Other Revenue includes revenue related to late payment charges, mutual assistance, off-system sales, and service application fees. Other revenue increased for the year ended December 31, 2021 compared to the same period in 2020, as BGE had temporarily suspended customer disconnections for non-payment and temporarily ceased new late fees for all customers in 2020 which has resumed in 2021.

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

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

The increase of $184 million for the year ended December 31, 2021 compared to the same period in 2020, respectively, in **Purchased power and fuel expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	2021 vs. 2020
	Increase (Decrease)
BSC costs	19
Storm-related costs	7
Credit loss expense	2
Labor, other benefits, contracting, and materials	4
Pension and non-pension postretirement benefits expense	1
Small business grants commitment[a]	(15)
Other	(3)
	15
Regulatory required programs	7
Total increase	$ 22

(a) Reflects charitable contributions expensed as a result of a commitment in 2020 to a multi-year small business grants program.

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

	2021 vs. 2020
	Increase (Decrease)
Depreciation and amortization[a]	$ 44
Regulatory required programs	(4)
Regulatory asset amortization	1
Total increase	$ 41

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

Taxes other than income taxes increased for the year ended December 31, 2021 compared to the same period in 2020, primarily due to higher property taxes.

Effective income tax rates were (9.4)% and 10.5% for the years ended December 31, 2021 and 2020, respectively. The change is primarily due to the multi-year plan which resulted in the acceleration of certain income tax benefits and the April 24, 2020 settlement agreement of ongoing transmission related income tax regulatory liabilities. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on both the three-year electric and natural gas distribution multi-year plans and the April 24, 2020 settlement agreement 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, 2021 compared to the same period in 2020. See the Results of Operations for Pepco, DPL, and ACE for additional information.

	2021	2020	Favorable (Unfavorable) Variance
PHI	$ 561	$ 495	$ 66
Pepco	296	266	30
DPL	128	125	3
ACE	146	112	34
Other[(a)]	(9)	(8)	(1)

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

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020. **Net income** increased by $66 million primarily due to favorable impacts as a result of rate case outcomes, higher transmission revenues due to an increase in capital investments in DPL's and ACE's service territories, higher distribution revenues due to an increase in volume in ACE's service territory, favorable weather conditions in DPL's Delaware electric service territory, a decrease in storm costs due to the August 2020 storms in Delaware at DPL, a decrease in credit loss expense at Pepco and DPL, and partially offset by recognition of a valuation allowance against a deferred tax asset at DPL, due to a change in Delaware tax law and an increase in depreciation and amortization expense.

Results of Operations—Pepco

	2021	2020	Favorable (Unfavorable) Variance
Operating revenues	$ 2,274	$ 2,149	$ 125
Operating expenses			
Purchased power	624	602	(22)
Operating and maintenance	471	453	(18)
Depreciation and amortization	403	377	(26)
Taxes other than income taxes	373	367	(6)
Total operating expenses	1,871	1,799	(72)
Gain on sales of assets	—	9	(9)
Operating income	403	359	44
Other income and (deductions)			
Interest expense, net	(140)	(138)	(2)
Other, net	48	38	10
Total other income and (deductions)	(92)	(100)	8
Income before income taxes	311	259	52
Income taxes	15	(7)	(22)
Net income	$ 296	$ 266	$ 30

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020. **Net income** increased by $30 million primarily due to favorable impacts of the Maryland and District of Columbia multi-year plans, and a decrease in credit loss expense, partially offset by an increase in depreciation and amortization expense and various operating expenses.

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

	2021 vs. 2020
	Increase
Distribution	$ 31
Transmission	32
Other	7
	70
Regulatory required programs	55
Total increase	$ 125

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution in both Maryland and the District of Columbia are not impacted by abnormal weather or usage per customer as a result of a BSA that provides for a fixed distribution charge per customer by customer class. While Operating revenues are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on revenue decoupling for Pepco Maryland and District of Columbia.

Number of Electric Customers	As of December 31, 2021	2020
Residential	841,831	832,190
Small commercial & industrial	54,216	53,800
Large commercial & industrial	22,568	22,459
Public authorities & electric railroads	181	168
Total	918,796	908,617

Distribution Revenue increased for the year ended December 31, 2021 compared to the same period in 2020, primarily due to favorable impacts of the Maryland and District of Columbia multi-year plans in 2021.

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. Transmission revenue increased for the year ended December 31, 2021 compared to the same period in 2020 primarily due to the reduction in revenue in 2020 due to the settlement agreement of ongoing transmission related income tax regulatory liabilities and increases in underlying costs.

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

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

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

The increase of $22 million for the year ended December 31, 2021 compared to the same period in 2020, in **Purchased power expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	2021 vs. 2020
	Increase (Decrease)
Storm related costs	$ 5
BSC and PHISCO costs	3
Pension and non-pension postretirement benefits expense	(4)
Labor, other benefits, contracting, and materials	(5)
Credit loss expense	(6)
Other	21
	14
Regulatory required programs	4
Total increase	$ 18

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

	2021 vs. 2020
	Increase (Decrease)
Depreciation and amortization[(a)]	$ 17
Regulatory asset amortization	(13)
Regulatory required programs	22
Total increase	$ 26

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

Taxes other than income taxes increased for the year ended December 31, 2021 compared to the same period in 2020, primarily due to an increase in property taxes.

Gain on sales of assets decreased for the year ended December 31, 2021 compared to the year ended December 31, 2020 due to the sale of land in the fourth quarter of 2020.

Other, **net** increased for the year ended December 31, 2021 compared to the same period in 2020, primarily due to higher AFUDC equity.

Effective income tax rates were 4.8% and (2.7)% for the years ended December 31, 2021 and 2020, respectively. The change is primarily related to the settlement agreement of ongoing transmission-related income tax regulatory liabilities, partially offset by the multi-year plan which resulted in the acceleration of certain income tax benefits. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the three-year electric distribution multi-year plan and the April 24, 2020 settlement agreement, 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

	2021	2020	Favorable (Unfavorable) Variance
Operating revenues	$ 1,380	$ 1,271	$ 109
Operating expenses			
Purchased power and fuel	539	503	(36)
Operating and maintenance	345	361	16
Depreciation and amortization	210	191	(19)
Taxes other than income taxes	67	65	(2)
Total operating expenses	1,161	1,120	(41)
Operating income	219	151	68
Other income and (deductions)			
Interest expense, net	(61)	(61)	—
Other, net	12	10	2
Total other income and (deductions)	(49)	(51)	2
Income before income taxes	170	100	70
Income taxes	42	(25)	(67)
Net income	$ 128	$ 125	$ 3

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020. **Net income** increased by $3 million primarily due to higher electric distribution rates, a decrease in storm costs due to the August 2020 storms in Delaware, a decrease in credit loss expense, higher transmission revenues due to an increase in capital investments, and favorable weather conditions at DPL's Delaware electric service territories, which was partially offset by the recognition of a valuation allowance against a deferred tax asset due to a change in Delaware tax law and an increase in depreciation and amortization expense.

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

	2021 vs. 2020		
	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ 5	$ 1	$ 6
Volume	1	(1)	—
Distribution	21	2	23
Transmission	33	—	33
Other	2	—	2
	62	2	64
Regulatory required programs	41	4	45
Total increase	$ 103	$ 6	$ 109

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution in Maryland are not impacted by abnormal weather or usage per customer as a result of a BSA that provides for a fixed distribution charge per customer by customer class. While Operating revenues from electric distribution in Maryland are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on revenue decoupling for DPL Maryland.

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, 2021 compared to the same period in 2020, Operating revenues related to weather increased due to favorable weather conditions in DPL's Delaware electric 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, 2021 compared to same period in 2020 and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Delaware Electric Service Territory	**2021**	**2020**	**Normal**	**2021 vs. 2020**	**2021 vs. Normal**
Heating Degree-Days	4,239	4,146	4,608	2.2 %	(8.0)%
Cooling Degree-Days	1,380	1,264	1,256	9.2 %	9.9 %

	For the Years Ended December 31,			% Change	
Delaware Natural Gas Service Territory	**2021**	**2020**	**Normal**	**2021 vs. 2020**	**2021 vs. Normal**
Heating Degree-Days	4,239	4,146	4,679	2.2 %	(9.4)%

Volume, exclusive of the effects of weather, remained relatively consistent for the year ended December 31, 2021 compared to the same period in 2020.

Electric Retail Deliveries to Delaware Customers (in GWhs)	**2021**	**2020**	**% Change 2021 vs. 2020**	**Weather - Normal % Change (b)**
Residential	3,214	3,149	2.1 %	(0.1)%
Small commercial & industrial	1,452	1,255	15.7 %	14.4 %
Large commercial & industrial	3,149	3,225	(2.4)%	(2.9)%
Public authorities & electric railroads	34	32	6.3 %	9.1 %
Total electric retail deliveries(a)	7,849	7,661	2.5 %	1.1 %

	As of December 31,	
Number of Total Electric Customers (Maryland and Delaware)	**2021**	**2020**
Residential	476,260	472,621
Small commercial & industrial	63,195	62,461
Large commercial & industrial	1,218	1,223
Public authorities & electric railroads	604	609
Total	541,277	536,914

(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)	**2021**	**2020**	**% Change 2021 vs. 2020**	**Weather - Normal % Change(b)**
Residential	7,914	7,832	1.0 %	(0.9)%
Small commercial & industrial	3,747	3,718	0.8 %	(1.2)%
Large commercial & industrial	1,679	1,703	(1.4)%	(1.5)%
Transportation	6,778	6,631	2.2 %	1.7 %
Total natural gas deliveries(a)	20,118	19,884	1.2 %	(0.2)%

Number of Delaware Natural Gas Customers	As of December 31, 2021	2020
Residential	128,121	127,128
Small commercial & industrial	10,027	10,017
Large commercial & industrial	20	16
Transportation	158	161
Total	138,326	137,322

(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, 2021 compared to the same period in 2020 primarily due to higher electric distribution rates in Maryland that became effective in July 2020 and higher electric distribution rates in Delaware that became effective in October 2020.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. Transmission revenue increased for the year ended December 31, 2021 compared to the same period in 2020 primarily due to the reduction in revenue in 2020 due to the settlement agreement of ongoing transmission related income tax regulatory liabilities and increases in underlying costs and capital investments.

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

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

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

The increase of $36 million for the year ended December 31, 2021 compared to the same period in 2020, in **Purchased power and fuel expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	2021 vs. 2020 (Decrease) Increase
Storm-related costs	$ (20)
Credit loss expense	(7)
Pension and non-pension postretirement benefits expense	(3)
Labor, other benefits, contracting, and materials	(2)
BSC and PHISCO costs	10
Other	7
	(15)
Regulatory required programs	(1)
Total decrease	$ (16)

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

	2021 vs. 2020 Increase (Decrease)
Depreciation and amortization[(a)]	$ 14
Regulatory asset amortization	(1)
Regulatory required programs	6
Total increase	$ 19

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

Effective income tax rates were 24.7% and (25.0)% for the years ended December 31, 2021 and 2020, respectively. The increase for the year ended December 31, 2021 is primarily related to the recognition of a valuation allowance against a deferred tax asset associated with Delaware net operating loss carryforwards due to a change in Delaware tax law and nonrecurring impact related to the settlement agreement of transmission-related income tax regulatory liabilities in 2020. See Note 3 — Regulatory Matters for additional information on the April 24, 2020 settlement agreement, 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

	2021	2020	Favorable (Unfavorable) Variance
Operating revenues	$ 1,388	$ 1,245	$ 143
Operating expenses			
Purchased power	694	609	(85)
Operating and maintenance	320	326	6
Depreciation and amortization	179	180	1
Taxes other than income taxes	8	8	—
Total operating expenses	1,201	1,123	(78)
Gain on sale of assets	—	2	(2)
Operating income	187	124	63
Other income and (deductions)			
Interest expense, net	(58)	(59)	1
Other, net	4	6	(2)
Total other income and (deductions)	(54)	(53)	(1)
Income before income taxes	133	71	62
Income taxes	(13)	(41)	(28)
Net income	$ 146	$ 112	$ 34

***Year Ended December 31, 2021 Compared to Year Ended December 31, 2020*.** **Net income** increased $34 million primarily due to favorable impacts as a result of outcomes from a distribution base rate case, higher distribution revenues due to an increase in volume, and higher transmission revenues due to an increase in capital investments which was partially offset by an increase in depreciation and amortization expense.

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

	2021 vs. 2020
	Increase (Decrease)
Weather	$ 2
Volume	17
Distribution	1
Transmission	51
Other	(3)
	68
Regulatory required programs	75
Total increase	$ 143

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution in New Jersey are not impacted by abnormal weather or usage per customer as a result of the Conservation Incentive Program (CIP) which became effective, prospectively, in the third quarter of 2021. The CIP compares current distribution revenues by customer class to approved target revenues established in ACE's most recent distribution base rate case. The CIP is calculated annually, and recovery is subject to certain conditions, including an earnings test and ceilings on customer rate increases. While Operating revenues are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers. See Note 3 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information on the ACE CIP.

Weather. Prior to the third quarter of 2021, the demand for electricity was affected by weather conditions. With respect to the electric business, very warm weather in summer months and very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity. Conversely, mild weather reduces demand. There was an increase related to weather for the year ended December 31, 2021 compared to the same period in 2020 due to the absence of impacts in the second half of 2021 as a result of the CIP.

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, 2021 compared to same period in 2020, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2021**	**2020**	**Normal**	**2021 vs. 2020**	**2021 vs. Normal**
Heating Degree-Days	4,256	4,029	4,609	5.6 %	(7.7)%
Cooling Degree-Days	1,284	1,314	1,197	(2.3)%	7.3 %

Volume, exclusive of the effects of weather, increased for the year ended December 31, 2021 compared to the same period in 2020, primarily due to customer growth, usage and absence of impacts in the second half of 2021 as a result of the CIP.

Electric Retail Deliveries to Customers (in GWhs)	**2021**	**2020**	**% Change 2021 vs. 2020**	**Weather - Normal % Change[b]**
Residential	4,220	4,029	4.7 %	3.8 %
Small commercial & industrial	1,409	1,277	10.3 %	10.0 %
Large commercial & industrial	3,146	3,067	2.6 %	2.8 %
Public authorities & electric railroads	46	47	(2.1)%	(1.9)%
Total retail deliveries[a]	8,821	8,420	4.8 %	4.3 %

	As of December 31,	
Number of Electric Customers	**2021**	**2020**
Residential	499,628	497,672
Small commercial & industrial	61,900	61,622
Large commercial & industrial	3,156	3,282
Public authorities & electric railroads	717	701
Total	565,401	563,277

(a) Reflects delivery volumes from customers purchasing electricity directly from ACE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.

(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 20-year average.

Distribution Revenue remained relatively consistent for the year ended December 31, 2021 compared to the same period in 2020.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered. Transmission revenue increased for the year ended December 31, 2021 compared to the same period in 2020 primarily due to the reduction in revenue in 2020 due to the settlement agreement of ongoing transmission-related income tax regulatory liabilities and increases in underlying costs and capital investments.

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

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, 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 $85 million for the year ended December 31, 2021 compared to same period in 2020, in **Purchased power expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	2021 vs. 2020 (Decrease) Increase
Storm-related costs	$ (9)
Pension and non-pension postretirement benefits expense	(1)
Labor, other benefits, contracting and materials	1
BSC and PHISCO costs	7
Other	(6)
	(8)
Regulatory required programs[a]	2
Total decrease	$ (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:

	2021 vs. 2020 Increase (Decrease)
Depreciation and amortization[a]	$ 15
Regulatory asset amortization	(1)
Regulatory required programs	(15)
Total decrease	$ (1)

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

Effective income tax rates were (9.8)% and (57.7)% for the years ended December 31, 2021 and 2020, respectively. The change is primarily related to the settlement agreement of ongoing transmission-related income tax regulatory liabilities, partially offset by the July 14, 2021 settlement which allowed ACE to retain certain tax benefits. See Note 3 — Regulatory Matters for additional information on the April 24, 2020 and July 14, 2021 settlement agreements, 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—Generation

	2021	2020	Favorable (Unfavorable) Variance
Operating revenues	$ 19,649	$ 17,603	$ 2,046
Operating expenses			
Purchased power and fuel	12,163	9,585	(2,578)
Operating and maintenance	4,555	5,168	613
Depreciation and amortization	3,003	2,123	(880)
Taxes other than income taxes	475	482	7
Total operating expenses	20,196	17,358	(2,838)
Gain on sales of assets and businesses	201	11	190
Operating (loss) income	(346)	256	(602)
Other income and (deductions)			
Interest expense, net	(297)	(357)	60
Other, net	795	937	(142)
Total other income and (deductions)	498	580	(82)
Income before income taxes	152	836	(684)
Income taxes	225	249	24
Equity in losses of unconsolidated affiliates	(10)	(8)	(2)
Net (loss) income	(83)	579	(662)
Net income (loss) attributable to noncontrolling interests	122	(10)	132
Net (loss) income attributable to membership interest	$ (205)	$ 589	$ (794)

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020. **Net income attributable to membership interest** decreased by $794 million primarily due to:

- Impacts of the February 2021 extreme cold weather event;
- Accelerated depreciation and amortization associated with Generation's previous decision in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021, a decision which was reversed on September 15, 2021, and Generation's decision in the third quarter of 2020 to early retire Mystic Units 8 and 9 in 2024;
- Decommissioning-related activities that were not offset for the Byron units beginning in the second quarter of 2021 through September 15, 2021. With Generation's September 15, 2021 reversal of the previous decision to retire Byron, Generation resumed contractual offset for Byron as of that date;
- Impairments of the New England asset group, the Albany Green Energy biomass facility at Generation, and a wind project at Generation, partially offset by the absence of an impairment of the New England asset group in the third quarter of 2020;
- Higher net unrealized and realized losses on equity investments; and
- The absence of prior year one-time tax settlements.

The decreases were partially offset by:

- Higher mark-to-market gains;
- Higher net unrealized and realized gains on NDT funds;
- Absence of one time charges recorded in 2020 associated with Generation's decision to early retire the Byron and Dresden nuclear facilities and Mystic Units 8 and 9, and the reversal of one-time

charges resulting from the reversal of the previous decision to early retire Byron and Dresden on September 15, 2021;

- Favorable sales and hedges of excess emission credits;
- Favorable commodity prices on fuel hedges;
- Lower nuclear fuel costs due to accelerated amortization of nuclear fuel and lower prices; and
- Higher New York ZEC revenues due to higher generation and an increase in ZEC prices.

Operating revenues. 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.

For the year ended December 31, 2021 compared to 2020, Operating revenues by region were as follows:

			2021 vs. 2020	
	2021	**2020**	**Variance**	**% Change[(a)]**
Mid-Atlantic[(b)]	$ 4,584	$ 4,645	$ (61)	(1.3)%
Midwest[(c)]	4,060	4,024	36	0.9 %
New York	1,575	1,431	144	10.1 %
ERCOT	1,181	958	223	23.3 %
Other Power Regions	4,890	4,002	888	22.2 %
Total electric revenues	16,290	15,060	1,230	8.2 %
Other	3,992	2,433	1,559	64.1 %
Mark-to-market (losses) gains	(633)	110	(743)	
Total Operating revenues	$ 19,649	$ 17,603	$ 2,046	11.6 %

(a) % Change in mark-to-market is not a meaningful measure.
(b) Includes results of transactions with PECO, BGE, Pepco, DPL, and ACE.
(c) Includes results of transactions with ComEd.

Supply Sources. Generation's supply sources by region are summarized below:

			2021 vs. 2020	
Supply Source (GWhs)	**2021**	**2020**	**Variance**	**% Change**
Nuclear Generation[a]				
Mid-Atlantic	53,589	52,202	1,387	2.7 %
Midwest	93,107	96,322	(3,215)	(3.3)%
New York	28,291	26,561	1,730	6.5 %
Total Nuclear Generation	174,987	175,085	(98)	(0.1)%
Fossil and Renewables				
Mid-Atlantic	2,271	2,206	65	2.9 %
Midwest	1,083	1,240	(157)	(12.7)%
New York	1	4	(3)	(75.0)%
ERCOT	13,187	11,982	1,205	10.1 %
Other Power Regions	9,995	11,121	(1,126)	(10.1)%
Total Fossil and Renewables	26,537	26,553	(16)	(0.1)%
Purchased Power				
Mid-Atlantic	13,576	22,487	(8,911)	(39.6)%
Midwest	561	770	(209)	(27.1)%
ERCOT	3,256	5,636	(2,380)	(42.2)%
Other Power Regions	50,212	51,079	(867)	(1.7)%
Total Purchased Power	67,605	79,972	(12,367)	(15.5)%
Total Supply/Sales by Region				
Mid-Atlantic[b]	69,436	76,895	(7,459)	(9.7)%
Midwest[b]	94,751	98,332	(3,581)	(3.6)%
New York	28,292	26,565	1,727	6.5 %
ERCOT	16,443	17,618	(1,175)	(6.7)%
Other Power Regions	60,207	62,200	(1,993)	(3.2)%
Total Supply/Sales by Region	269,129	281,610	(12,481)	(4.4)%

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants. Includes the total output for fully owned plants and the total output for CENG prior to the acquisition of EDF's interest on August 6, 2021 as CENG was fully consolidated. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on Generation's acquisition of EDF's interest in 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.

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.

	2021	**2020**
Nuclear fleet capacity factor	94.5 %	95.4 %
Refueling outage days	262	260
Non-refueling outage days	34	19

ZEC Prices. Generation is compensated through state programs for the carbon-free attributes of its nuclear generation. ZEC prices have a significant impact on operating revenues. The following table presents the average ZEC prices ($/MWh) for each of Generation's major regions in which state programs have been enacted. Prices reflect the weighted average price for the various delivery periods within each calendar year.

			2021 vs. 2020	
State (Region)	**2021**	**2020**	**Variance**	**% Change**
New Jersey (Mid-Atlantic)	$ 10.00	$ 10.00	$ —	— %
Illinois (Midwest)	16.50	16.50	—	— %
New York (New York)	20.93	19.59	1.34	6.8 %

Capacity Prices. Generation participates in capacity auctions in each of its major regions, except ERCOT which does not have a capacity market. Generation also incurs capacity costs associated with load served, except in ERCOT. Capacity prices have a significant impact on Generation's operating revenues and purchased power and fuel. The following table presents the average capacity prices ($/MW Day) for each of Generation's major regions. Prices reflect the weighted average price for the various auction periods within each calendar year.

			2021 vs. 2020	
Location (Region)	**2021**	**2020**	**Variance**	**% Change**
Eastern Mid-Atlantic Area Council (Mid-Atlantic and Midwest)	$ 174.96	$ 159.50	$ 15.46	9.7 %
ComEd (Midwest)	192.45	194.22	(1.77)	(0.9)%
Rest of State (New York)	98.35	47.81	50.54	105.7 %
Southeast New England (Other)	163.66	200.69	(37.03)	(18.5)%

Electricity Prices. The price of electricity has a significant impact on Generation's operating revenues and purchased power cost. The following table presents the average day-ahead around-the-clock price ($/MWh) for each of Generation's major regions.

			2021 vs. 2020	
Location (Region)	**2021**	**2020**	**Variance**	**% Change**
PJM West (Mid-Atlantic)	$ 38.91	$ 20.95	$ 17.96	85.7 %
ComEd (Midwest)	34.76	18.96	15.80	83.3 %
Central (New York)	29.90	16.36	13.54	82.8 %
North (ERCOT)	146.63	22.03	124.60	565.6 %
Southeast Massachusetts (Other)(a)	46.38	23.57	22.81	96.8 %

(a) Reflects New England, which comprises the majority of the activity in the Other region.

For the year ended December 31, 2021 compared to 2020, changes in **Operating revenues** by region were approximately as follows:

	2021 vs. 2020		
	Variance	% Change[a]	Description
Mid-Atlantic	$ (61)	(1.3)%	• unfavorable wholesale load revenue of $(520) primarily due to lower volumes; partially offset by • favorable settled economic hedges of $365 due to settled prices relative to hedged prices • favorable retail load revenue of $95 primarily due to higher prices
Midwest	36	0.9 %	• favorable net wholesale load and generation revenue of $540 primarily due to higher prices, partially offset by decreased generation due to higher nuclear outage days • unfavorable settled economic hedges of $(525) due to settled prices relative to hedged prices
New York	144	10.1 %	• favorable nuclear generation revenue of $75 primarily due to higher prices and lower nuclear outage days • favorable ZEC revenue of $70 due to higher prices and higher nuclear generation
ERCOT	223	23.3 %	• favorable retail load revenue of $140 primarily due to higher prices in part due to the February 2021 extreme cold weather event • favorable settled economic hedges of $65 due to settled prices relative to hedged prices
Other Power Regions	888	22.2 %	• favorable settled economic hedges of $655 due to settled prices relative to hedged prices • favorable retail load revenue of $535 due to higher prices and higher volumes; partially offset by • unfavorable wholesale load revenue of $(380) primarily due to lower volumes
Other	1,559	64.1 %	• favorable gas revenue of $1,375 primarily due to higher prices in part due to the February 2021 extreme cold weather event
Mark-to-market[b]	(743)		• losses on economic hedging activities of $(633) in 2021 compared to gains of $110 in 2020
Total	$ 2,046	11.6 %	

(a) % Change in mark-to-market is not a meaningful measure.

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

Purchased power and fuel. See Operating revenues above for discussion of Generation's reportable segments and hedging strategies and for supplemental statistical data, including supply sources by region, nuclear fleet capacity factor, capacity prices, and electricity prices.

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 purchased power and fuel expense or results of operations, and accelerated nuclear fuel amortization associated with nuclear decommissioning.

For the year ended December 31, 2021 compared to 2020, Purchased power and fuel by region were as follows:

			2021 vs. 2020	
	2021	**2020**	**Variance**	**% Change[a]**
Mid-Atlantic[b]	$ 2,320	$ 2,442	$ 122	5.0 %
Midwest[c]	1,343	1,121	(222)	(19.8)%
New York	414	434	20	4.6 %
ERCOT	2,006	532	(1,474)	(277.1)%
Other Power Regions	3,999	3,336	(663)	(19.9)%
Total electric purchased power and fuel	10,082	7,865	(2,217)	(28.2)%
Other	3,279	1,904	(1,375)	(72.2)%
Mark-to-market gains	(1,198)	(184)	1,014	
Total purchased power and fuel	$ 12,163	$ 9,585	$ (2,578)	(26.9)%

(a) % Change in mark-to-market is not a meaningful measure.
(b) Includes results of transactions with PECO, BGE, Pepco, DPL, and ACE.
(c) Includes results of transactions with ComEd.

For the year ended December 31, 2021 compared to 2020, changes in **Purchased power and fuel** by region were approximately as follows:

	2021 vs. 2020		
	Variance	% Change[(a)]	Description
Mid-Atlantic	$ 122	5.0 %	• favorable purchased power and net capacity impact of $80 primarily due to higher nuclear generation, lower load and higher capacity prices earned partially offset by lower cleared capacity volumes • favorable settlement of economic hedges of $70 due to settled prices relative to hedged prices
Midwest	(222)	(19.8)%	• unfavorable purchased power and net capacity impact of $(330) primarily due to higher energy prices, lower nuclear generation, lower cleared capacity volumes, and lower capacity prices; partially offset by • favorable nuclear fuel cost of $75 primarily due to accelerated amortization of nuclear fuel and lower nuclear fuel prices
New York	20	4.6 %	• favorable settlement of economic hedges of $45 due to settled prices relative to hedged prices; partially offset by • unfavorable purchased power and net capacity impact of $(40) primarily due to higher energy prices partially offset by higher nuclear generation and higher capacity prices earned
ERCOT	(1,474)	(277.1)%	• unfavorable purchased power of $(755) primarily due to higher energy prices primarily during the February 2021 extreme cold weather event • unfavorable settlement of economic hedges of $(535) due to settled prices relative to hedged prices • unfavorable fuel cost of $(170) primarily due to higher gas prices
Other Power Regions	(663)	(19.9)%	• unfavorable purchased power and net capacity impact of $(855) primarily due to higher energy prices, lower generation, lower cleared capacity volumes, and lower capacity prices • unfavorable fuel cost of $(80) primarily due to higher gas prices; partially offset by • net favorable environmental products activity of $270 primarily driven by favorable emissions activity partially offset by unfavorable RPS activity
Other	(1,375)	(72.2)%	• unfavorable net gas purchase costs and settlement of economic hedges of $(1,150) • unfavorable accelerated nuclear fuel amortization associated with announced early plant retirements of $(90)
Mark-to-market[(b)]	1,014		• gains on economic hedging activities of $1,198 in 2021 compared to gains of $184 in 2020
Total	$ (2,578)	(26.9)%	

(a) % Change in mark-to-market is not a meaningful measure.

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

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

	2021 vs. 2020 (Decrease) Increase
Plant retirements and divestitures[(a)]	$ (484)
ARO update	(109)
Labor, other benefits, contracting, and materials	(64)
Insurance	(45)
Cost management program	(34)
Nuclear refueling outage costs, including the co-owned Salem plants	(16)
Corporate allocations	(14)
Acquisition related costs	15
Credit loss expense	21
Asset impairments	27
Separation costs	49
Other	41
Total decrease	$ (613)

(a) Primarily reflects contractual offset of accelerated depreciation and amortization associated with Generation's previous decision to early retire the Byron and Dresden nuclear facilities. See Note 10 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

Depreciation and amortization expense increased for the year ended December 31, 2021 compared to the same period in 2020, primarily due to the accelerated depreciation and amortization associated with Generation's previous decision to early retire the Byron and Dresden nuclear facilities. This decision was reversed on September 15, 2021 and depreciation for Byron and Dresden was adjusted beginning September 15, 2021 to reflect the extended useful life estimates. A portion of this accelerated depreciation and amortization is offset in Operating and maintenance expense.

Gain on sales of assets and businesses increased for the year ended December 31, 2021 compared to the same period in 2020, primarily due to gains on sales of equity investments that became publicly traded entities in the fourth quarter of 2020 and the first half of 2021 and a gain on sale of Generation's solar business.

Interest expense, net decreased for the year ended December 31, 2021 compared to the same period in 2020, primarily due to decreased expense related to the CR nonrecourse senior secured term loan credit facility and interest rate swaps, and decreases in interest rates. See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the CR credit facility and interest rate swaps.

Other, net decreased for the year ended December 31, 2021 compared to the same period in 2020, due to activity described in the table below:

	2021	2020
Net unrealized gains on NDT funds[(a)]	$ 204	$ 391
Net realized gains on sale of NDT funds[(a)]	381	70
Interest and dividend income on NDT funds[(a)]	98	90
Contractual elimination of income tax expense[(b)]	226	180
Net unrealized (losses) gains from equity investments[(c)]	(160)	186
Other	46	20
Total other, net	$ 795	$ 937

(a) Unrealized gains, realized gains, and interest and dividend income on the NDT funds are associated with the Non-Regulatory Agreement Units. In addition, also includes unrealized gains, realized gains, and interest and dividend income on the NDT funds associated with the Byron units as decommissioning-related impacts were not offset starting in the second quarter of 2021 due to the inability to recognize a regulatory asset at ComEd. With the September 15, 2021 reversal of the previous decision to retire Byron, Generation resumed contractual offset for Byron as of that date. See Note 10 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

(b) Contractual elimination of income tax expense is associated with the income taxes on the NDT funds of the Regulatory Agreement Units.

(c) Net unrealized gains and losses from equity investments that became publicly traded entities in the fourth quarter of 2020 and the first half of 2021.

Effective income tax rates were 148.0% and 29.8% for the years ended December 31, 2021 and 2020, respectively. The higher effective tax rate in 2021 is primarily due to the impacts of the February 2021 extreme cold weather event on Income before income taxes. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Net income attributable to noncontrolling interests increased for the year ended December 31, 2021 compared to the same period in 2020, primarily due to CENG's results of operations prior to Generation's acquisition of EDF's interest in CENG on August 6, 2021.

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, 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. 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 $10.3 billion, as of December 31, 2021. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings, and to issue letters of credit. See the "Credit Matters" section below for additional information. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs, and capital expenditure requirements. See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' debt and credit agreements.

Cash Flows from Operating Activities (All Registrants)

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. Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers.

See Note 3 — Regulatory Matters and Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on regulatory and legal proceedings and proposed legislation.

The following table provides a summary of the change in cash flows from operating activities for the years ended December 31, 2021 and 2020 by Registrant:

(Decrease) increase in cash flows from operating activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net income	$ (125)	$ 304	$ 57	$ 59	$ 66	$ 30	$ 3	$ 34
Adjustments to reconcile net income to cash:								
Non-cash operating activities	(332)	12	11	(35)	45	35	23	(15)
Option premiums paid, net	(199)	—	—	—	—	—	—	—
Collateral (posted) received, net	(568)	(14)	—	—	—	—	—	—
Income taxes	187	(8)	(26)	(40)	42	12	38	1
Pension and non-pension postretirement benefit contributions	(64)	(48)	—	(3)	(9)	—	(1)	(1)
Changes in working capital and other noncurrent assets and liabilities	(122)	25	(46)	(136)	11	(116)	50	77
(Decrease) increase in cash flows from operating activities	$ (1,223)	$ 271	$ (4)	$ (155)	$ 155	$ (39)	$ 113	$ 96

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 2021 and 2020 were as follows:

- See Note 24 —Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements and the Registrants' Consolidated Statements of Cash Flows for additional information on **non-cash operating activities**.

- **Option premiums paid** relate to options contracts that Generation purchases and sells as part of its established policies and procedures to manage risks associated with market fluctuations in commodity prices. See Note 16 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on derivative contracts.

- Depending upon whether Exelon is in a net mark-to-market liability or asset position, **collateral** may be required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on an exchange or in the over-the-counter markets. See Note 16 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' collateral.

- See Note 14 —Income Taxes of the Combined Notes to Consolidated Financial Statements and the Registrants' Consolidated Statements of Cash Flows for additional information on **income taxes.**

- **Changes in working capital and other noncurrent assets and liabilities** include a decrease in Accounts receivable at Exelon resulting from the impact of cash received in 2020 related to the revolving accounts receivable financing arrangement entered into on April 8, 2020, and an increase in Accounts payable and accrued expenses at Exelon resulting from the impact of certain penalties for natural gas delivery associated with the February 2021 extreme cold weather event at

Generation and increases in natural gas prices at Generation. See Note 6 — Accounts Receivable and Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the sales of customer accounts receivable and on the February 2021 extreme cold weather event, respectively.

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, 2021 and 2020 by Registrant:

Increase (decrease) in cash flows from investing activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Capital expenditures	$ 67	$ (170)	$ (93)	$ 21	$ (116)	$ (70)	$ (5)	$ (44)
Investment in NDT fund sales, net	(18)	—	—	—	—	—	—	—
Collection of DPP	131	—	—	—	—	—	—	—
Proceeds from sales of assets and businesses	831	—	—	—	—	—	—	—
Changes in intercompany money pool	—	—	(68)	—	—	—	—	—
Other investing activities	8	24	2	16	(5)	(1)	7	(5)
Increase (decrease) in cash flows from investing activities	$ 1,019	$ (146)	$ (159)	$ 37	$ (121)	$ (71)	$ 2	$ (49)

Significant investing cash flow impacts for the Registrants for 2021 and 2020 were as follows:

- Variances in **capital expenditures** are primarily due to the timing of cash expenditures for capital projects. See the "Credit Matters" section below for additional information on projected capital expenditure spending.

- See Note 6 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information on the **Collection of DPP**.

- **Proceeds from sales of assets and businesses** increased primarily due to the sale of a significant portion of Exelon's solar business and a biomass facility and proceeds received on sales of equity investments. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the sale of Exelon's solar business and biomass facility.

- Changes in **intercompany money pool** are driven by short-term borrowing needs. Refer below for more information regarding the intercompany money pool.

Cash Flows from Financing Activities (All Registrants)

The following table provides a summary of the change in cash flows from financing activities for the years ended December 31, 2021 and 2020 by Registrant:

Increase (decrease) in cash flows from financing activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Changes in short-term borrowings, net	$ 638	$ (516)	$ —	$ 206	$ (60)	$ 187	$ (87)	$(160)
Long-term debt, net	774	300	100	(100)	91	(22)	27	86
Changes in intercompany money pool	—	—	(80)	—	(23)	—	—	—
Dividends paid on common stock	(5)	(8)	1	(46)	—	(36)	(6)	(174)
Acquisition of noncontrolling interest	(885)	—	—	—	—	—	—	—
Distributions to member	—	—	—	—	(150)	—	—	—
Contributions from/(to) parent/member	—	79	166	(154)	189	(18)	8	202
Other financing activities	91	(3)	(5)	2	(7)	—	(3)	(4)
Increase (decrease) in cash flows from financing activities	$ 613	$ (148)	$ 182	$ (92)	$ 40	$ 111	$ (61)	$ (50)

Significant financing cash flow impacts for the Registrants for 2021 and 2020 were as follows:

- **Changes in short-term borrowings, net**, is driven by repayments on and issuances of notes due in less than 365 days. Refer to 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 below for more information regarding the intercompany money pool.

- Exelon’s ability to pay **dividends** on its common stock depends on the receipt of dividends paid by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. See Note 19 - Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on dividend restrictions. See below for quarterly dividends declared.

- See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information related to the **acquisition** of CENG noncontrolling interest.

- **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 2021 and 2020 by Registrant was as follows:

During 2021, the following long-term debt was issued:

Company/ Subsidiary	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon[a]	Long-Term Software License Agreements	3.62 %	December 1, 2025	$ 4	Procurement of software licenses.
ComEd	First Mortgage Bonds, Series 130	3.13 %	March 15, 2051	700	Repay a portion of outstanding commercial paper obligations and two outstanding term loans, and to fund other general corporate purposes.
ComEd	First Mortgage Bonds, Series 131	2.75 %	September 1, 2051	450	Refinance existing indebtedness and for general corporate purposes.
PECO	First and Refunding Mortgage Bonds	3.05 %	March 15, 2051	375	Funding for general corporate purposes.
PECO	First and Refunding Mortgage Bonds	2.85 %	September 15, 2051	375	Refinance existing indebtedness and for general corporate purposes.
BGE	Senior Notes	2.25 %	June 15, 2031	600	Repay a portion of outstanding commercial paper obligations, repay existing indebtedness, and to fund other general corporate purposes.
Pepco	First Mortgage Bonds	2.32 %	March 30, 2031	150	Repay existing indebtedness and for general corporate purposes.
Pepco	First Mortgage Bonds	3.29 %	September 28, 2051	125	Repay existing indebtedness and for general corporate purposes.
DPL[b]	First Mortgage Bonds	3.24 %	March 30, 2051	125	Repay existing indebtedness and for general corporate purposes.
ACE	First Mortgage Bonds	2.30 %	March 15, 2031	350	Refinance existing indebtedness, repay outstanding commercial paper obligations, and for general corporate purposes.
ACE[c]	First Mortgage Bonds	2.27 %	February 15, 2032	75	Repay existing indebtedness and for general corporate purposes.
Generation	West Medway II Nonrecourse Debt[d]	LIBOR + 3%[e]	March 31, 2026	150	Funding for general corporate purposes.
Generation	Energy Efficiency Project Financing[f]	2.53% - 4.24%	January 31, 2022 - February 28, 2022	2	Funding to install energy conservation measures.

(a) In connection with the separation, Exelon Corporate entered into three 18-month term loan agreements. On January 21, 2022, two of the loan agreements were issued for $300 million each with an expiration date of July 21, 2023. On January 24, 2022, the third loan agreement was issued for $250 million with an expiration date of July 24, 2023. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to SOFR plus 0.65%.

(b) On November 16, 2021, DPL entered into a purchase agreement of First Mortgage Bonds of $125 million at 3.06% due on February 15, 2052. The closing date of the issuance occurred on February 15, 2022.

(c) On November 16, 2021, ACE entered into a purchase agreement of First Mortgage Bonds of $25 million and $150 million at 2.27% and 3.06% due on February 15, 2032 and February 15, 2052, respectively. The closing date of the issuance occurred on February 15, 2022.

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

(e) The nonrecourse debt has an average blended interest rate.

(f) 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 issued:

Company/ Subsidiary	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.
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[a]	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.
Generation	Senior Notes	3.25 %	June 1, 2025	900	Repay existing indebtedness and for general corporate purposes.
Generation	Constellation Renewables Nonrecourse Debt[b]	LIBOR + 2.75%	December 15, 2027	750	Repay existing indebtedness and for general corporate purposes.
Generation	Energy Efficiency Project Financing[c]	2.53% - 3.95%	February 28, 2021 - March 31, 2021	6	Funding to install energy conservation measures.

(a) The bonds have a 1.05% interest rate through July 2025.
(b) See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on nonrecourse debt.
(c) 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 2021, the following long-term debt was retired and/or redeemed:

Company/ Subsidiary	Type	Interest Rate	Maturity	Amount
Exelon	Senior Notes[a]	2.45%	April 15, 2021	$ 300
Exelon	Long-Term Software License Agreements	3.95%	May 1, 2024	24
Exelon	Long-Term Software License Agreements	3.62%	December 1, 2025	1
ComEd	First Mortgage Bonds	3.40%	September 1, 2021	350
PECO	First Mortgage Bonds	1.70%	September 15, 2021	300
BGE	Senior Notes	3.50%	November 15, 2021	300
ACE	First Mortgage Bonds	4.35%	April 1, 2021	200
ACE	Tax-Exempt First Mortgage Bonds	6.80%	March 1, 2021	39
ACE	Transition Bonds	5.55%	October 20, 2021	21
Generation	Continental Wind Nonrecourse Debt[b]	6.00%	February 28, 2033	35
Generation	CR Nonrecourse Debt[b]	3-month LIBOR + 2.50%[c]	December 15, 2027	17
Generation	SolGen Nonrecourse Debt[b]	3.93%	September 30, 2036	7
Generation	Antelope Valley DOE Nonrecourse Debt[b]	2.29% - 3.56%	January 5, 2037	24
Generation	West Medway II Nonrecourse Debt[b]	LIBOR + 3%[d]	March 31, 2026	13
Generation	RPG Nonrecourse Debt[b]	4.11%	March 31, 2035	9

(a) As part of the 2012 Constellation merger, Exelon entered intercompany loan agreements that mirrored the terms and amounts of the third-party debt obligations. In connection with the separation, on January 31, 2022, Exelon Corporate received cash from Generation of $258 million to settle the intercompany loan. See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the mirror debt.

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

(c) The interest rate was amended to 3-month LIBOR + 2.50% on June 16, 2021.

(d) The nonrecourse debt has an average blended interest rate.

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

Company/ Subsidiary	Type	Interest Rate	Maturity	Amount
Exelon	Notes	2.85%	June 15, 2020	$ 900
Exelon	Long-Term Software License Agreements	3.95%	May 1, 2024	24
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
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	CR 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

(a) The senior notes are legacy Constellation mirror debt that were previously held at Exelon. As part of the 2012 Constellation merger, Exelon assumed intercompany loan agreements that mirrored the terms and amounts of external obligations held by Exelon. See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

(b) 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, 2021 and for the first quarter of 2022 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share[a]
First Quarter 2021	February 21, 2021	March 8, 2021	March 15, 2021	$ 0.3825
Second Quarter 2021	April 27, 2021	May 14, 2021	June 10, 2021	$ 0.3825
Third Quarter 2021	July 27, 2021	August 13, 2021	September 10, 2021	$ 0.3825
Fourth Quarter 2021	October 29, 2021	November 15, 2021	December 10, 2021	$ 0.3825
First Quarter 2022	February 8, 2022	February 25, 2022	March 10, 2022	$ 0.3375

(a) Exelon's Board of Directors approved an updated dividend policy for 2022. The 2022 quarterly dividend will be $0.3375 per share.

Credit Matters and Cash Requirements (All Registrants)

The Registrants fund liquidity needs for capital expenditures, 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 $10.3 billion in aggregate total commitments of which $6.5 billion was available to support additional commercial paper as of December 31, 2021, and of which no financial institution has more than 7% of the aggregate commitments for the Registrants. On February 1, 2022, Exelon Corporate and the Utility Registrants each entered into a new 5-year revolving credit facility that replaced its existing syndicated revolving credit facility. See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information. The Registrants had access to the commercial paper markets and had availability under their revolving credit facilities during 2021 to fund their short-term liquidity needs, when necessary. Exelon and Generation used their available credit facilities to manage short-term liquidity needs as a result of the impacts of the February 2021 extreme cold weather event. 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 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 to support the estimated future cash requirements discussed below.

Pursuant to the Separation Agreement between Exelon and Constellation Energy Corporation, Exelon made a cash payment of $1.75 billion to Generation on January 31, 2022. See Note 26 — Separation of the Combined Notes to Consolidated Financial Statements for additional information on the separation.

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, 2021 and available credit facility capacity prior to any incremental collateral at December 31, 2021:

	PJM Credit Policy Collateral	Other Incremental Collateral Required[(a)]	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 28	$ —	$ 998
PECO	1	37	600
BGE	4	78	470
Pepco	3	—	125
DPL	4	14	151
ACE	1	—	155

(a) Represents incremental collateral related to natural gas procurement contracts.

Capital Expenditures

As of December 31, 2021, estimates of capital expenditures for plant additions and improvements are as follows:

(in millions)	2022 Transmission	2022 Distribution	2022 Gas	Total 2022[b]	Beyond 2022[b][c]
Exelon[a]	N/A	N/A	N/A	$ 8,600	$ 24,950
ComEd	450	2,025	N/A	2,475	7,775
PECO	175	850	325	1,325	4,500
BGE	275	500	475	1,225	4,100
PHI	600	1,175	100	1,850	5,650
Pepco	275	625	N/A	900	2,750
DPL	150	250	100	475	1,550
ACE	175	300	N/A	475	1,375

(a) Exelon's estimated capital expenditures include estimated capital expenditures for Generation.
(b) Numbers rounded to the nearest $25M and may not sum due to rounding.
(c) Includes estimated capital expenditures for the Utility Registrants from 2023 and 2025 and includes estimated capital expenditures for Generation from 2023 to 2024.

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

Projected 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.

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.

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 2022. Exelon's estimated contributions include contributions related to Generation's qualified pension plans. In connection with the separation, an additional qualified pension contribution of $207 million was completed on February 1, 2022. 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 2022:

	Qualified Pension Plans	Non-Qualified Pension Plans	OPEB
Exelon[(a)]	$ 505	$ 32	$ 50
ComEd	173	2	12
PECO	12	1	2
BGE	48	2	16
PHI	60	10	7
Pepco	2	1	6
DPL	1	1	—
ACE	7	—	—

(a) Exelon's estimated contributions include contributions related to Generation's qualified pension plans. These payments are based on the combined plans, as of December 31, 2021 and do not reflect the impacts of the separation.

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

See Note 15 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information on pension and OPEB contributions.

Cash Requirements for Other Financial Commitments

The following tables summarize the Registrants' future estimated cash payments as of December 31, 2021 under existing financial commitments:

Exelon

	2022[a]	Beyond 2022[a]	Total[a]	Time Period
Long-term debt[b]	$ 3,357	$ 35,300	$ 38,657	2022 - 2053
Interest payments on long-term debt[c]	1,509	23,670	25,179	2022 - 2051
Operating leases[d]	99	937	1,036	2022 - 2106
Purchase power obligations[e]	620	1,109	1,729	2022 - 2036
Fuel purchase agreements[f]	1,303	5,446	6,749	2022 - 2054
Electric supply procurement	2,122	1,254	3,376	2022 - 2025
Long-term renewable energy and REC commitments	302	1,691	1,993	2022 - 2033
Other purchase obligations[g]	5,247	5,806	11,053	2022 - 2046
DC PLUG obligation	33	37	70	2022 - 2024
SNF obligation	—	1,210	1,210	2022 - 2035
Pension contributions[h]	505	190	695	2022 - 2027
Total cash requirements	$ 15,097	$ 76,650	$ 91,747	

(a) Exelon's future estimated cash payments include future estimated cash payments for Generation.

(b) Includes amounts from ComEd and PECO financing trusts.

(c) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2021 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, 2021. Includes estimated interest payments due to ComEd and PECO financing trusts.

(d) Capacity payments associated with contracted generation lease agreements are net of sublease and capacity offsets of $57 million and $315 million for 2022 and beyond 2022, respectively, and $372 million in total.

(e) 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.

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

(g) Represents the future estimated value at December 31, 2021 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants or subsidiary 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.

(h) These amounts represent Exelon's expected contributions to its qualified pension plans. Qualified pension contributions for years after 2027 are not included.

ComEd

	2022	Beyond 2022	Total	Time Period
Long-term debt[a]	$ —	$ 10,084	$ 10,084	2022 - 2053
Interest payments on long-term debt[b]	394	7,467	7,861	2022 - 2051
Operating leases	2	3	5	2022 - 2025
Electric supply procurement	474	260	734	2022 - 2024
Long-term renewable energy and REC commitments	271	1,438	1,709	2022 - 2033
Other purchase obligations[c]	858	764	1,622	2022 - 2031
ZEC commitments	160	706	866	2022 - 2027
Total cash requirements	$ 2,159	$ 20,722	$ 22,881	

(a) Includes amounts from ComEd financing trust.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2021 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, 2021 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

	2022	Beyond 2022	Total	Time Period
Long-term debt[a]	$ 350	$ 4,084	$ 4,434	2022 - 2051
Interest payments on long-term debt[b]	166	3,213	3,379	2022 - 2051
Operating leases	—	1	1	2022 - 2034
Fuel purchase agreements[c]	140	271	411	2022 - 2029
Electric supply procurement	490	2	492	2022 - 2023
Other purchase obligations[d]	846	690	1,536	2022 - 2030
Total cash requirements	$ 1,992	$ 8,261	$ 10,253	

(a) Includes amounts from PECO financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2021 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, 2021 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

	2022	Beyond 2022	Total	Time Period
Long-term debt	$ 250	$ 3,750	$ 4,000	2022 - 2050
Interest payments on long-term debt[a]	138	2,312	2,450	2022 - 2050
Operating leases	16	19	35	2022 - 2106
Fuel purchase agreements[b]	112	481	593	2022 - 2038
Electric supply procurement	764	498	1,262	2022 - 2024
Other purchase obligations[c]	692	607	1,299	2022 - 2040
Total cash requirements	$ 1,972	$ 7,667	$ 9,639	

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2021 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, 2021 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

	2022	Beyond 2022	Total	Time Period
Long-term debt	$ 387	$ 6,618	$ 7,005	2022 - 2051
Interest payments on long-term debt[a]	282	3,953	4,235	2022 - 2051
Finance leases	12	67	79	2022 - 2029
Operating leases	38	230	268	2022 - 2032
Fuel purchase agreements[b]	31	242	273	2022 - 2030
Electric supply procurement	1,097	754	1,851	2022 - 2025
Long-term renewable energy and REC commitments	31	253	284	2022 - 2032
Other purchase obligations[c]	1,016	1,031	2,047	2022 - 2029
DC PLUG obligation	33	37	70	2022 - 2024
Total cash requirements	$ 2,927	$ 13,185	$ 16,112	

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2021 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, 2021.

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

(c) Represents the future estimated value at December 31, 2021 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

	2022	Beyond 2022	Total	Time Period
Long-term debt	$ 309	$ 3,150	$ 3,459	2022 - 2051
Interest payments on long-term debt[(a)]	149	2,287	2,436	2022 - 2051
Finance leases	4	23	27	2022 - 2029
Operating leases	8	47	55	2022 - 2032
Electric supply procurement	498	384	882	2022 - 2025
Other purchase obligations[(b)]	603	551	1,154	2022 - 2026
DC PLUG obligation	33	37	70	2022 - 2024
Total cash requirements	$ 1,604	$ 6,479	$ 8,083	

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2021 and do not reflect anticipated future refinancing, early redemptions, or debt issuances.

(b) Represents the future estimated value at December 31, 2021 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

	2022	Beyond 2022	Total	Time Period
Long-term debt	$ 78	$ 1,711	$ 1,789	2022 - 2051
Interest payments on long-term debt[(a)]	63	1,013	1,076	2022 - 2051
Finance leases	5	27	32	2022 - 2029
Operating leases	10	60	70	2022 - 2027
Fuel purchase agreements[(b)]	31	242	273	2022 - 2030
Electric supply procurement	298	187	485	2022 - 2024
Long-term renewable energy and REC commitments	31	253	284	2022 - 2032
Other purchase obligations[(c)]	214	192	406	2022 - 2028
Total cash requirements	$ 730	$ 3,685	$ 4,415	

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2021 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, 2021.

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

(c) Represents the future estimated value at December 31, 2021 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

	2022	Beyond 2022	Total	Time Period
Long-term debt	$ —	$ 1,572	$ 1,572	2022 - 2050
Interest payments on long-term debt(a)	56	519	575	2022 - 2050
Finance leases	3	17	20	2022 - 2029
Operating leases	4	9	13	2022 - 2027
Electric supply procurement	301	183	484	2022 - 2024
Other purchase obligations(b)	158	240	398	2022 - 2027
Total cash requirements	$ 522	$ 2,540	$ 3,062	

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2021 and do not reflect anticipated future refinancing, early redemptions, or debt issuances.

(b) Represents the future estimated value at December 31, 2021 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 the financial commitments in the tables above 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

Credit Facilities (All Registrants)

Exelon Corporate, ComEd, and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. PECO meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. Pepco, DPL, and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the PHI intercompany money pool. PHI Corporate meets its short-term liquidity requirements primarily through the issuance of short-term notes and the Exelon intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

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

Capital Structure

At December 31, 2021, the capital structures of the Registrants consisted of the following:

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Long-term debt	50 %	44 %	44 %	45 %	40 %	49 %	48 %	48 %
Long-term debt to affiliates[(a)]	1 %	1 %	2 %	— %	— %	— %	— %	— %
Common equity	45 %	55 %	54 %	53 %	— %	49 %	48 %	48 %
Member's equity	— %	— %	— %	— %	57 %	— %	— %	— %
Commercial paper and notes payable	4 %	— %	— %	2 %	3 %	2 %	4 %	4 %

(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 mandatory 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 (All Registrants)

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 additional 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 and the Utility Registrants did not change for the year ended December 31, 2021. On January 14, 2022, Fitch lowered Exelon Corporate's long-term rating from BBB+ to BBB and affirmed the short-term rating of F2. In addition, Fitch upgraded Pepco, ACE, and PHI's long-term rating from BBB to BBB+ and upgraded Pepco and ACE's senior secured rating from A- to A.

Intercompany Money Pool (All Registrants)

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, 2021, are presented in the following tables. ACE did not have any intercompany money pool activity as of December 31, 2021.

	For the Year Ended December 31, 2021		As of December 31, 2021
Exelon Intercompany Money Pool	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
Exelon Corporate	$ 735	$ —	$ 217
Generation	—	(426)	—
PECO	303	(100)	—
BSC	—	(435)	(260)
PHI Corporate	—	(40)	(7)
PCI	60	—	50

	For the Year Ended December 31, 2021		As of December 31, 2021
PHI Intercompany Money Pool	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
Pepco	$ —	$ (30)	$ —
DPL	30	—	—

Shelf Registration Statements (All Registrants)

Exelon 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 (All Registrants)

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, 2021					
	Short-term Financing Authority[a]			Remaining Long-term Financing Authority		
	Commission	**Expiration Date**	**Amount**	**Commission**	**Expiration Date**	**Amount**
ComEd[b]	FERC	December 31, 2023	$ 2,500	ICC	January 1, 2025	$ 2,093
PECO[c]	FERC	December 31, 2023	1,500	PAPUC	December 31, 2024	1,900
BGE	FERC	December 31, 2023	700	MDPSC	N/A	500
Pepco	FERC	December 31, 2023	500	MDPSC / DCPSC	December 31, 2022	625
DPL	FERC	December 31, 2023	500	MDPSC / DEPSC	December 31, 2022	172
ACE[d]	NJBPU	December 31, 2023	350	NJBPU	December 31, 2022	175

(a) On October 15, 2021, ComEd, PECO, BGE, Pepco, and DPL filed applications with FERC and on July 21, 2021, ACE filed an application with NJBPU for renewal of their short-term financing authority through December 31, 2023. ComEd received approval on December 16, 2021, PECO and BGE received approval on December 23, 2021, Pepco and DPL received approval on December 28, 2021, and ACE received approval on December 1, 2021.

(b) On November 18, 2021, ComEd had an additional $2 billion in new money long-term debt financing authority from the ICC with an effective date of January 1, 2022 and an expiration date of January 1, 2025.

(c) On December 2, 2021, PECO received approval from the PAPUC for $2.5 billion in new long-term debt financing authority with an effective date of January 1, 2022.

(d) ACE is currently in the process of renewing its long-term financing authority with the NJBPU and expects approval by August 1, 2022.

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 manages these risks through risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. Historically, reporting on risk management issues has been to Exelon's Risk Management Committee, the Risk Management Committees of each Utility Registrant, and the Risk Committee of Exelon's Board of Directors. After separation, reporting on risk management issues will be to Exelon's Executive Committee, the Risk Management Committees of each Utility Registrant, and the Audit and Risk Committee of Exelon's Board of Directors.

Commodity Price Risk (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. We expect the settlement of the majority of our economic hedges will occur during 2022 through 2024.

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. For merchant revenues not already hedged via comprehensive state programs, such as the CMC in Illinois, we utilize a three-year ratable sales plan to align our hedging strategy with our financial objectives. The prompt three-year merchant revenues are hedged on an approximate rolling 90%/60%/30% basis. We may also enter transactions that are outside of this ratable hedging program.As of December 31, 2021, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 92%-95% and 73%-76% for 2022 and 2023, respectively. 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, CMC payments, and certain non-derivative contracts.

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/MWh reduction in the annual average around-the-clock energy price based on December 31, 2021 market conditions and hedged position would be a decrease in pre-tax net income of approximately $20 million and $243 million for 2022 and 2023, respectively. 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.

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 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 (including Generation's) and ComEd’s trading and non-trading marketing activities is 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 and ComEd’s commodity mark-to-market net asset or liability balance sheet position from December 31, 2019 to December 31, 2021. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings. This table excludes all NPNS contracts and does not segregate proprietary trading activity. See Note 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, 2021 and 2020.

	Exelon	ComEd
Balance as of December 31, 2019	$ 567 [a]	$ (301)
Total change in fair value during 2020 of contracts recorded in result of operations	(203)	—
Reclassification to realized at settlement of contracts recorded in results of operations	469	—
Changes in allocated collateral	(513)	—
Net option premium paid	139	—
Option premium amortization	(104)	—
Upfront payments and amortizations[c]	73	—
Balance as of December 31, 2020	428 [a]	(301)
Total change in fair value during 2021 of contracts recorded in result of operations	797	—
Reclassification to realized at settlement of contracts recorded in results of operations	(228)	—
Changes in fair value—recorded through regulatory assets[b]	82	82
Changes in allocated collateral	96	—
Net option premium paid	338	—
Option premium amortization	(125)	—
Upfront payments and amortizations[c]	15	—
Balance as of December 31, 2021	$ 1,403 [a]	$ (219)

(a) Exelon's balance related to Generation is 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, 2020 and 2021, ComEd recorded a regulatory asset of $301 million and $219 million, respectively, related to its mark-to-market derivative liabilities with unaffiliated suppliers. ComEd recorded $33 million of decreases in fair value and an increase for realized losses due to settlements of $33 million in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2020. ComEd recorded $62 million of increases in fair value and an increase for realized losses due to settlements of $20 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2021.

(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 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 Exelon's and ComEd's total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of Exelon's and ComEd's 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						
	2022	2023	2024	2025	2026	2027 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[(a)(b)(c)]:							
Actively quoted prices (Level 1)	$ 711	$ 66	$ 53	$ 43	$ 24	$ —	$ 897
Prices provided by external sources (Level 2)	442	436	(60)	1	—	—	819
Prices based on model or other valuation methods (Level 3)[(d)]	19	(93)	2	(15)	(45)	(181)	(313)
Total	$1,172	$ 409	$ (5)	$ 29	$ (21)	$ (181)	$ 1,403

(a) Exelon's maturity by year includes maturities related to Generation's mark-to-market contract net assets (liabilities).

(b) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.

(c) Amounts are shown net of collateral paid/(received) from counterparties (and offset against mark-to-market assets and liabilities) of $512 million at December 31, 2021.

(d) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

ComEd

	Maturities Within						
	2022	2023	2024	2025	2026	2027 and Beyond	Total Fair Value
Commodity derivative contracts[(a)]:							
Prices based on model or other valuation methods (Level 3)[(a)]	$ (18)	$ (19)	$ (21)	$ (20)	$ (21)	$ (120)	$ (219)

(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, NPNS, and payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2021. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The 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, 2021	Total Exposure Before Credit Collateral	Credit Collateral[a]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 715	$ 176	$ 539	1	$ 106
Non-investment grade	13	—	13	—	—
No external ratings					
Internally rated—investment grade	111	—	111	—	—
Internally rated—non-investment grade	226	47	179	—	—
Total	$ 1,065	$ 223	$ 842	1	$ 106

(a) As of December 31, 2021, credit collateral held from counterparties where Generation had credit exposure included $163 million of cash and $60 million of letters of credit.

	Maturity of Credit Risk Exposure			
Rating as of December 31, 2021	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 605	$ 62	$ 48	$ 715
Non-investment grade	13	—	—	13
No external ratings				
Internally rated—investment grade	111	—	—	111
Internally rated—non-investment grade	181	39	6	226
Total	$ 910	$ 101	$ 54	$ 1,065

Net Credit Exposure by Type of Counterparty	As of December 31, 2021
Financial institutions	$ 32
Investor-owned utilities, marketers, power producers	711
Energy cooperatives and municipalities	62
Other	37
Total	$ 842

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, 2021. 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, 2021, the Utility Registrants net credit exposure to suppliers was immaterial. See Note 16 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

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. 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, 2021, 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. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the February 2021 extreme cold weather event and Texas-based generating asset outages.

Exchange Traded Transactions (Exelon, 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)

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, 2021. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. See Note 16—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Equity Price Risk (Exelon)

Generation maintains trust funds, as required by the NRC, to fund certain costs of decommissioning its nuclear plants. Generation’s NDT funds are reflected at fair value in Exelon's 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 $892 million reduction in the fair value of the trust assets as of December 31, 2021. 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.

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, 2021. 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, 2021, Exelon’s internal control over financial reporting was effective.

The effectiveness of Exelon’s internal control over financial reporting as of December 31, 2021, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 25, 2022

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, 2021. 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, 2021, ComEd’s internal control over financial reporting was effective.

February 25, 2022

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, 2021. 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, 2021, PECO’s internal control over financial reporting was effective.

February 25, 2022

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, 2021. 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, 2021, BGE’s internal control over financial reporting was effective.

February 25, 2022

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, 2021. 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, 2021, PHI’s internal control over financial reporting was effective.

February 25, 2022

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, 2021. 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, 2021, Pepco’s internal control over financial reporting was effective.

February 25, 2022

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, 2021. 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, 2021, DPL’s internal control over financial reporting was effective.

February 25, 2022

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, 2021. 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, 2021, ACE's internal control over financial reporting was effective.

February 25, 2022

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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 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, 2021, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

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 permanent cessation of operations. To estimate its decommissioning obligations related to its nuclear generating stations for financial accounting and reporting purposes, management 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. 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, 2021, the nuclear decommissioning ARO was $12.7 billion.

The principal considerations for our determination that performing procedures relating to the Company’s annual nuclear decommissioning ARO assessment is a critical audit matter are the significant judgment by management when estimating its decommissioning obligations; this in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating the reasonableness of management’s discounted 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 estimating the decommissioning obligations by evaluating the appropriateness of the discounted 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, 8, 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 or asset groups are potentially impaired by comparing the undiscounted expected future cash flows to the carrying value when indicators of impairment exist. When the undiscounted cash flow analysis indicates a long-lived asset or asset group may not be recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. The fair value analysis is primarily based on the income approach using significant unobservable inputs including revenue and generation forecasts, projected capital and maintenance expenditures, and discount rates. As of December 31, 2021, the total carrying value of long-lived generation assets subject to this assessment was $19.6 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 and estimating the fair value of these long-lived generation assets or 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 assess the recoverability and estimate the fair value of the Company's long-lived generation assets or asset groups. These procedures also included, among others, testing management's process for developing the expected future cash flows for the long-lived generation assets or 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. Evaluating the reasonableness of the revenue and generation forecasts involved considering whether the forecasts were consistent with future commodity prices and external market data. Professionals with specialized skill and knowledge were used to assist in evaluating the reasonableness of the 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 the 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, 2021, there were $9.5 billion of regulatory assets and $10.0 billion of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to the Company'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 new and existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's interpretation of regulatory guidance and proceedings and the related accounting implications, and recalculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 25, 2022

We have served as the Company's auditor since 2000.

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)(2)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(2)(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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 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 audits 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 the 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, 2021, there were $2.2 billion of regulatory assets and $6.9 billion of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to the Company'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 new and existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's interpretation of regulatory guidance and proceedings and the related accounting implications, and recalculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 25, 2022

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)(3)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(3)(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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 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 audits 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 the 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, 2021, there were $991 million of regulatory assets and $729 million of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to the Company’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 new and existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company’s correspondence with regulators, evaluating the reasonableness of management’s interpretation of regulatory guidance and proceedings and the related accounting implications, and recalculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 25, 2022

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)(4)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(4)(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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 in conformity with accounting principles generally accepted in the United States of America.

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 audits 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 the 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, 2021, there were $692 million of regulatory assets and $960 million of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to the Company'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 new and existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's interpretation of regulatory guidance and proceedings and the related accounting implications, and recalculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 25, 2022

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)(5)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(5)(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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 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 audits 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 the 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, 2021, there were $2.2 billion of regulatory assets and $1.3 billion of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to the Company'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 new and existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's interpretation of regulatory guidance and proceedings and the related accounting implications, and recalculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 25, 2022

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)(6)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(6)(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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 in conformity with accounting principles generally accepted in the United States of America.

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 audits 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 the 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, 2021, there were $745 million of regulatory assets and $563 million of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to the Company'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 new and existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's interpretation of regulatory guidance and proceedings and the related accounting implications, and recalculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 25, 2022

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)(7)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(7)(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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 in conformity with accounting principles generally accepted in the United States of America.

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 audits 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 the 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, 2021, there were $280 million of regulatory assets and $466 million of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to the Company’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 new and existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company’s correspondence with regulators, evaluating the reasonableness of management’s interpretation of regulatory guidance and proceedings and the related accounting implications, and recalculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 25, 2022

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)(8)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(8)(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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021 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 audits 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 the 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, 2021, there were $491 million of regulatory assets and $252 million of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to the Company’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 new and existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company’s correspondence with regulators, evaluating the reasonableness of management’s interpretation of regulatory guidance and proceedings and the related accounting implications, and recalculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 25, 2022

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)	2021	2020	2019
Operating revenues			
Competitive businesses revenues	$ 18,467	$ 16,400	$ 17,754
Rate-regulated utility revenues	17,709	16,633	16,839
Revenues from alternative revenue programs	171	6	(155)
Total operating revenues	36,347	33,039	34,438
Operating expenses			
Competitive businesses purchased power and fuel	12,157	9,592	10,849
Rate-regulated utility purchased power and fuel	5,207	4,512	4,648
Operating and maintenance	8,659	9,408	8,615
Depreciation and amortization	6,036	5,014	4,252
Taxes other than income taxes	1,766	1,714	1,732
Total operating expenses	33,825	30,240	30,096
Gain on sales of assets and businesses	201	24	31
Gain on deconsolidation of business	—	—	1
Operating income	2,723	2,823	4,374
Other income and (deductions)			
Interest expense, net	(1,546)	(1,610)	(1,591)
Interest expense to affiliates	(25)	(25)	(25)
Other, net	1,056	1,145	1,227
Total other income and (deductions)	(515)	(490)	(389)
Income before income taxes	2,208	2,333	3,985
Income taxes	370	373	774
Equity in losses of unconsolidated affiliates	(9)	(6)	(183)
Net income	1,829	1,954	3,028
Net income (loss) attributable to noncontrolling interests	123	(9)	92
Net income attributable to common shareholders	$ 1,706	$ 1,963	$ 2,936
Comprehensive income, net of income taxes			
Net income	$ 1,829	$ 1,954	$ 3,028
Other comprehensive income (loss), net of income taxes			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	(4)	(40)	(65)
Actuarial loss reclassified to periodic benefit cost	223	190	149
Pension and non-pension postretirement benefit plan valuation adjustment	432	(357)	(289)
Unrealized loss on cash flow hedges	(1)	(3)	—
Unrealized gain on investments in unconsolidated affiliates	—	—	1
Unrealized gain on foreign currency translation	—	4	6
Other comprehensive income (loss)	650	(206)	(198)
Comprehensive income	2,479	1,748	2,830
Comprehensive income (loss) attributable to noncontrolling interests	123	(9)	93
Comprehensive income attributable to common shareholders	$ 2,356	$ 1,757	$ 2,737
Average shares of common stock outstanding:			
Basic	979	976	973
Assumed exercise and/or distributions of stock-based awards	1	1	1
Diluted[a]	980	977	974
Earnings per average common share:			
Basic	$ 1.74	$ 2.01	$ 3.02
Diluted	$ 1.74	$ 2.01	$ 3.01

(a) The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was zero for the year ended December 31, 2021 and less than 1 million for the years ended December 31, 2020 and 2019.

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Cash Flows

	For the Years Ended December 31,		
(In millions)	**2021**	**2020**	**2019**
Cash flows from operating activities			
Net income	$ 1,829	$ 1,954	$ 3,028
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	7,573	6,527	5,780
Asset impairments	552	591	201
Gain on sales of assets and businesses	(201)	(24)	(27)
Deferred income taxes and amortization of investment tax credits	18	309	681
Net fair value changes related to derivatives	(568)	(268)	222
Net realized and unrealized gains on NDT funds	(586)	(461)	(663)
Net unrealized losses (gains) on equity investments	160	(186)	—
Other non-cash operating activities	(200)	592	613
Changes in assets and liabilities:			
Accounts receivable	(703)	697	(243)
Inventories	(141)	(85)	(87)
Accounts payable and accrued expenses	440	(129)	(425)
Option premiums paid, net	(338)	(139)	(29)
Collateral (posted) received, net	(74)	494	(438)
Income taxes	327	140	(64)
Pension and non-pension postretirement benefit contributions	(665)	(601)	(408)
Other assets and liabilities	(4,411)	(5,176)	(1,482)
Net cash flows provided by operating activities	3,012	4,235	6,659
Cash flows from investing activities			
Capital expenditures	(7,981)	(8,048)	(7,248)
Proceeds from NDT fund sales	6,532	3,341	10,051
Investment in NDT funds	(6,673)	(3,464)	(10,087)
Collection of DPP	3,902	3,771	—
Acquisitions of assets and businesses, net	—	—	(41)
Proceeds from sales of assets and businesses	877	46	53
Other investing activities	26	18	12
Net cash flows used in investing activities	(3,317)	(4,336)	(7,260)
Cash flows from financing activities			
Changes in short-term borrowings	269	161	781
Proceeds from short-term borrowings with maturities greater than 90 days	1,380	500	—
Repayments on short-term borrowings with maturities greater than 90 days	(350)	—	(125)
Issuance of long-term debt	3,481	7,507	1,951
Retirement of long-term debt	(1,640)	(6,440)	(1,287)
Dividends paid on common stock	(1,497)	(1,492)	(1,408)
Acquisition of CENG noncontrolling interest	(885)	—	—
Proceeds from employee stock plans	80	45	112
Other financing activities	(80)	(136)	(82)
Net cash flows provided by (used in) financing activities	758	145	(58)
Increase (decrease) in cash, restricted cash, and cash equivalents	453	44	(659)
Cash, restricted cash, and cash equivalents at beginning of period	1,166	1,122	1,781
Cash, restricted cash, and cash equivalents at end of period	$ 1,619	$ 1,166	$ 1,122
Supplemental cash flow information			
Increase (decrease) in capital expenditures not paid	$ 16	$ 194	$ (7)
Increase in DPP	3,652	4,441	—
Increase in PP&E related to ARO update	642	850	968

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2021	 2020
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,182	$ 663
Restricted cash and cash equivalents	393	438
Accounts receivable		
Customer accounts receivable	3,913	3,597
Customer allowance for credit losses	(375)	(366)
Customer accounts receivable, net	3,538	3,231
Other accounts receivable	1,664	1,469
Other allowance for credit losses	(76)	(71)
Other accounts receivable, net	1,588	1,398
Mark-to-market derivative assets	2,169	644
Inventories, net		
Fossil fuel and emission allowances	389	297
Materials and supplies	1,480	1,425
Regulatory assets	1,296	1,228
Renewable energy credits	529	633
Assets held for sale	13	958
Other	1,380	1,647
Total current assets	13,957	12,562
Property, plant, and equipment (net of accumulated depreciation and amortization of $30,318 and $26,727 as of December 31, 2021 and 2020, respectively)	84,219	82,584
Deferred debits and other assets		
Regulatory assets	8,224	8,759
Nuclear decommissioning trust funds	15,938	14,464
Investments	443	440
Goodwill	6,677	6,677
Mark-to-market derivative assets	949	555
Other	2,606	3,276
Total deferred debits and other assets	34,837	34,171
Total assets[a]	$ 133,013	$ 129,317

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 3,330	$ 2,031
Long-term debt due within one year	3,373	1,819
Accounts payable	4,136	3,562
Accrued expenses	1,955	2,078
Payables to affiliates	5	5
Regulatory liabilities	376	581
Mark-to-market derivative liabilities	999	295
Unamortized energy contract liabilities	91	100
Renewable energy credit obligation	779	661
Liabilities held for sale	3	375
Other	1,064	1,264
Total current liabilities	16,111	12,771
Long-term debt	35,324	35,093
Long-term debt to financing trusts	390	390
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	14,194	13,035
Asset retirement obligations	13,090	12,300
Pension obligations	2,990	4,503
Non-pension postretirement benefit obligations	1,687	2,011
Spent nuclear fuel obligation	1,210	1,208
Regulatory liabilities	9,628	9,485
Mark-to-market derivative liabilities	714	473
Unamortized energy contract liabilities	147	238
Other	2,733	2,942
Total deferred credits and other liabilities	46,393	46,195
Total liabilities[a]	98,218	94,449
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 979 shares and 976 shares outstanding as of December 31, 2021 and 2020, respectively)	20,324	19,373
Treasury stock, at cost (2 shares as of December 31, 2021 and 2020)	(123)	(123)
Retained earnings	16,942	16,735
Accumulated other comprehensive loss, net	(2,750)	(3,400)
Total shareholders' equity	34,393	32,585
Noncontrolling interests	402	2,283
Total equity	34,795	34,868
Total liabilities and shareholders' equity	$ 133,013	$ 129,317

(a) Exelon's consolidated assets include $2,549 million and $10,200 million as of December 31, 2021 and 2020, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $1,077 million and $3,598 million as of December 31, 2021 and 2020, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 23–Variable Interest Entities for additional information.

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, net	Noncontrolling Interests	Total Equity
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 loss, 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 loss, net of income taxes	—	—	—	—	(206)	—	(206)
Balance, December 31, 2020	977,466	$ 19,373	$ (123)	$ 16,735	$ (3,400)	$ 2,283	$ 34,868
Net income	—	—	—	1,706	—	123	1,829
Long-term incentive plan activity	1,734	69	—	—	—	—	69
Employee stock purchase plan issuances	2,091	90	—	—	—	—	90
Changes in equity of noncontrolling interests	—	—	—	—	—	(37)	(37)
Acquisition of CENG noncontrolling interest	—	1,080	—	—	—	(1,965)	(885)
Deferred tax adjustment related to acquisition of CENG noncontrolling interest	—	(290)	—	—	—	—	(290)
Common stock dividends ($1.53/common share)	—	—	—	(1,499)	—	—	(1,499)
Acquisition of other noncontrolling interest	—	2	—	—	—	(2)	—
Other comprehensive income, net of income taxes	—	—	—	—	650	—	650
Balance, December 31, 2021	981,291	$ 20,324	$ (123)	$ 16,942	$ (2,750)	$ 402	$ 34,795

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2021	2020	2019
Operating revenues			
Electric operating revenues	$ 6,323	$ 5,914	$ 5,850
Revenues from alternative revenue programs	42	(47)	(133)
Operating revenues from affiliates	41	37	30
Total operating revenues	6,406	5,904	5,747
Operating expenses			
Purchased power	1,888	1,653	1,565
Purchased power from affiliates	383	345	376
Operating and maintenance	1,048	1,231	1,041
Operating and maintenance from affiliates	307	289	264
Depreciation and amortization	1,205	1,133	1,033
Taxes other than income taxes	320	299	301
Total operating expenses	5,151	4,950	4,580
Gain on sales of assets	—	—	4
Operating income	1,255	954	1,171
Other income and (deductions)			
Interest expense, net	(376)	(369)	(346)
Interest expense to affiliates	(13)	(13)	(13)
Other, net	48	43	39
Total other income and (deductions)	(341)	(339)	(320)
Income before income taxes	914	615	851
Income taxes	172	177	163
Net income	$ 742	$ 438	$ 688
Comprehensive income	$ 742	$ 438	$ 688

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Cash Flows

	For the Years Ended December 31,		
(In millions)	2021	2020	2019
Cash flows from operating activities			
Net income	$ 742	$ 438	$ 688
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	1,205	1,133	1,033
Deferred income taxes and amortization of investment tax credits	244	228	109
Other non-cash operating activities	126	202	265
Changes in assets and liabilities:			
Accounts receivable	(25)	(10)	(34)
Receivables from and payables to affiliates, net	32	(1)	(12)
Inventories	(2)	(13)	(16)
Accounts payable and accrued expenses	—	63	(51)
Collateral received, net	—	14	48
Income taxes	—	8	95
Pension and non-pension postretirement benefit contributions	(196)	(148)	(77)
Other assets and liabilities	(531)	(590)	(345)
Net cash flows provided by operating activities	1,595	1,324	1,703
Cash flows from investing activities			
Capital expenditures	(2,387)	(2,217)	(1,915)
Other investing activities	26	2	29
Net cash flows used in investing activities	(2,361)	(2,215)	(1,886)
Cash flows from financing activities			
Changes in short-term borrowings	(323)	193	130
Issuance of long-term debt	1,150	1,000	700
Retirement of long-term debt	(350)	(500)	(300)
Dividends paid on common stock	(507)	(499)	(508)
Contributions from parent	791	712	250
Other financing activities	(16)	(13)	(16)
Net cash flows provided by financing activities	745	893	256
(Decrease) increase in cash, restricted cash, and cash equivalents	(21)	2	73
Cash, restricted cash, and cash equivalents at beginning of period	405	403	330
Cash, restricted cash, and cash equivalents at end of period	$ 384	$ 405	$ 403
Supplemental cash flow information			
(Decrease) increase in capital expenditures not paid	$ (46)	$ 109	$ (37)

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2021		December 31, 2020	
ASSETS				
Current assets				
Cash and cash equivalents		$ 131		$ 83
Restricted cash and cash equivalents		210		279
Accounts receivable				
Customer accounts receivable	647		656	
Customer allowance for credit losses	(73)		(97)	
Customer accounts receivable, net		574		559
Other accounts receivable	227		239	
Other allowance for credit losses	(17)		(21)	
Other accounts receivable, net		210		218
Receivables from affiliates		16		22
Inventories, net		170		170
Regulatory assets		335		279
Other		76		49
Total current assets		1,722		1,659
Property, plant, and equipment (net of accumulated depreciation and amortization of $6,099 and $5,672 as of December 31, 2021 and 2020, respectively)		25,995		24,557
Deferred debits and other assets				
Regulatory assets		1,870		1,749
Investments		6		6
Goodwill		2,625		2,625
Receivables from affiliates		2,761		2,541
Prepaid pension asset		1,086		1,022
Other		405		307
Total deferred debits and other assets		8,753		8,250
Total assets		$ 36,470		$ 34,466

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2021	2020
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 323
Long-term debt due within one year	—	350
Accounts payable	647	683
Accrued expenses	384	390
Payables to affiliates	121	96
Customer deposits	99	86
Regulatory liabilities	185	289
Mark-to-market derivative liabilities	18	33
Other	133	143
Total current liabilities	1,587	2,393
Long-term debt	9,773	8,633
Long-term debt to financing trusts	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,685	4,341
Asset retirement obligations	144	126
Non-pension postretirement benefits obligations	169	173
Regulatory liabilities	6,759	6,403
Mark-to-market derivative liabilities	201	268
Other	592	595
Total deferred credits and other liabilities	12,550	11,906
Total liabilities	24,115	23,137
Commitments and contingencies		
Shareholders' equity		
Common stock ($12.50 par value, 250 shares authorized, 127 shares outstanding as of December 31, 2021 and 2020)	1,588	1,588
Other paid-in capital	9,076	8,285
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	3,330	3,095
Total shareholders' equity	12,355	11,329
Total liabilities and shareholders' equity	$ 36,470	$ 34,466

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, 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
Net income	—	—	742	—	742
Appropriation of retained earnings for future dividends	—	—	(742)	742	—
Common stock dividends	—	—	—	(507)	(507)
Contributions from parent	—	791	—	—	791
Balance, December 31, 2021	$ 1,588	$ 9,076	$ (1,639)	$ 3,330	$ 12,355

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2021	2020	2019
Operating revenues			
Electric operating revenues	$ 2,613	$ 2,519	$ 2,505
Natural gas operating revenues	538	514	610
Revenues from alternative revenue programs	26	16	(21)
Operating revenues from affiliates	21	9	6
Total operating revenues	3,198	3,058	3,100
Operating expenses			
Purchased power	699	645	610
Purchased fuel	188	185	262
Purchased power from affiliates	194	188	157
Operating and maintenance	757	816	707
Operating and maintenance from affiliates	177	159	154
Depreciation and amortization	348	347	333
Taxes other than income taxes	184	172	165
Total operating expenses	2,547	2,512	2,388
Gain on sales of assets	—	—	1
Operating income	651	546	713
Other income and (deductions)			
Interest expense, net	(149)	(136)	(124)
Interest expense to affiliates, net	(12)	(11)	(12)
Other, net	26	18	16
Total other income and (deductions)	(135)	(129)	(120)
Income before income taxes	516	417	593
Income taxes	12	(30)	65
Net income	$ 504	$ 447	$ 528
Comprehensive income	$ 504	$ 447	$ 528

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2021	2020	2019
Cash flows from operating activities			
Net income	$ 504	$ 447	$ 528
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	348	347	333
Deferred income taxes and amortization of investment tax credits	11	(23)	20
Other non-cash operating activities	—	24	38
Changes in assets and liabilities:			
Accounts receivable	(35)	(88)	(29)
Receivables from and payables to affiliates, net	21	(6)	(5)
Inventories	(26)	(1)	4
Accounts payable and accrued expenses	15	63	(11)
Income taxes	5	31	(34)
Pension and non-pension postretirement benefit contributions	(18)	(18)	(28)
Other assets and liabilities	(52)	1	(65)
Net cash flows provided by operating activities	773	777	751
Cash flows from investing activities			
Capital expenditures	(1,240)	(1,147)	(939)
Changes in Exelon intercompany money pool	—	68	(68)
Other investing activities	9	7	(1)
Net cash flows used in investing activities	(1,231)	(1,072)	(1,008)
Cash flows from financing activities			
Issuance of long-term debt	750	350	325
Retirement of long-term debt	(300)	—	—
Changes in Exelon intercompany money pool	(40)	40	—
Dividends paid on common stock	(339)	(340)	(358)
Contributions from parent	414	248	188
Other financing activities	(9)	(4)	(6)
Net cash flows provided by financing activities	476	294	149
Increase (decrease) in cash, restricted cash, and cash equivalents	18	(1)	(108)
Cash, restricted cash, and cash equivalents at beginning of period	26	27	135
Cash, restricted cash, and cash equivalents at end of period	$ 44	$ 26	$ 27
Supplemental cash flow information			
Increase in capital expenditures not paid	$ 26	$ 55	$ 40

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

	December 31,			
(In millions)	2021		2020	
ASSETS				
Current assets				
Cash and cash equivalents		$ 36		$ 19
Restricted cash and cash equivalents		8		7
Accounts receivable				
Customer accounts receivable	489		511	
Customer allowance for credit losses	(105)		(116)	
Customer accounts receivable, net		384		395
Other accounts receivable	116		130	
Other allowance for credit losses	(7)		(8)	
Other accounts receivable, net		109		122
Receivables from affiliates		1		2
Inventories, net				
Fossil fuel		51		33
Materials and supplies		45		38
Regulatory assets		48		25
Other		29		21
Total current assets		711		662
Property, plant, and equipment (net of accumulated depreciation and amortization of $3,964 and $3,843 as of December 31, 2021 and 2020, respectively)		11,117		10,181
Deferred debits and other assets				
Regulatory assets		943		776
Investments		34		30
Receivables from affiliates		597		475
Prepaid pension asset		386		375
Other		36		32
Total deferred debits and other assets		1,996		1,688
Total assets		$ 13,824		$ 12,531

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2021	2020
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Long-term debt due within one year	$ 350	$ 300
Accounts payable	494	479
Accrued expenses	136	129
Payables to affiliates	70	50
Borrowings from Exelon intercompany money pool	—	40
Customer deposits	48	59
Regulatory liabilities	94	121
Other	35	30
Total current liabilities	1,227	1,208
Long-term debt	3,847	3,453
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,421	2,242
Asset retirement obligations	29	29
Non-pension postretirement benefits obligations	286	286
Regulatory liabilities	635	503
Other	83	93
Total deferred credits and other liabilities	3,454	3,153
Total liabilities	8,712	7,998
Commitments and contingencies		
Shareholder's equity		
Common stock (No par value, 500 shares authorized, 170 shares outstanding as of December 31, 2021 and 2020)	3,428	3,014
Retained earnings	1,684	1,519
Total shareholder's equity	5,112	4,533
Total liabilities and shareholder's equity	$ 13,824	$ 12,531

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
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
Net income	—	504	504
Common stock dividends	—	(339)	(339)
Contributions from parent	414	—	414
Balance, December 31, 2021	$ 3,428	$ 1,684	$ 5,112

Baltimore Gas and Electric Company
Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2021	2020	2019
Operating revenues			
Electric operating revenues	$ 2,497	$ 2,323	$ 2,368
Natural gas operating revenues	801	739	700
Revenues from alternative revenue programs	12	16	12
Operating revenues from affiliates	31	20	26
Total operating revenues	3,341	3,098	3,106
Operating expenses			
Purchased power	699	509	585
Purchased fuel	243	171	181
Purchased power and fuel from affiliates	233	311	286
Operating and maintenance	618	617	600
Operating and maintenance from affiliates	193	172	160
Depreciation and amortization	591	550	502
Taxes other than income taxes	283	268	260
Total operating expenses	2,860	2,598	2,574
Operating income	481	500	532
Other income and (deductions)			
Interest expense, net	(138)	(133)	(121)
Other, net	30	23	28
Total other income and (deductions)	(108)	(110)	(93)
Income before income taxes	373	390	439
Income taxes	(35)	41	79
Net income	$ 408	$ 349	$ 360
Comprehensive income	$ 408	$ 349	$ 360

Baltimore Gas and Electric Company
Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2021	2020	2019
Cash flows from operating activities			
Net income	$ 408	$ 349	$ 360
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	591	550	502
Deferred income taxes and amortization of investment tax credits	(17)	37	130
Other non-cash operating activities	75	97	85
Changes in assets and liabilities:			
Accounts receivable	30	(165)	25
Receivables from and payables to affiliates, net	(13)	(8)	1
Inventories	(29)	10	(1)
Accounts payable and accrued expenses	14	102	(43)
Income taxes	20	60	(67)
Pension and non-pension postretirement benefit contributions	(81)	(78)	(48)
Other assets and liabilities	(269)	(70)	(196)
Net cash flows provided by operating activities	729	884	748
Cash flows from investing activities			
Capital expenditures	(1,226)	(1,247)	(1,145)
Other investing activities	18	2	8
Net cash flows used in investing activities	(1,208)	(1,245)	(1,137)
Cash flows from financing activities			
Changes in short-term borrowings	130	(76)	40
Issuance of long-term debt	600	400	400
Retirement of long-term debt	(300)	—	—
Dividends paid on common stock	(292)	(246)	(224)
Contributions from parent	257	411	193
Other financing activities	(6)	(8)	(8)
Net cash flows provided by financing activities	389	481	401
(Decrease) increase in cash, restricted cash, and cash equivalents	(90)	120	12
Cash, restricted cash, and cash equivalents at beginning of period	145	25	13
Cash, restricted cash, and cash equivalents at end of period	$ 55	$ 145	$ 25
Supplemental cash flow information			
(Decrease) increase in capital expenditures not paid	$ (59)	$ 53	$ 6

Baltimore Gas and Electric Company
Balance Sheets

(In millions)	December 31, 2021		December 31, 2020	
ASSETS				
Current assets				
Cash and cash equivalents	$	51	$	144
Restricted cash and cash equivalents		4		1
Accounts receivable				
Customer accounts receivable	436		487	
Customer allowance for credit losses	(38)		(35)	
Customer accounts receivable, net		398		452
Other accounts receivable	124		117	
Other allowance for credit losses	(9)		(9)	
Other accounts receivable, net		115		108
Receivables from affiliates		1		3
Inventories, net				
Fossil fuel		42		25
Materials and supplies		53		41
Prepaid utility taxes		49		—
Regulatory assets		215		168
Other		8		6
Total current assets		936		948
Property, plant, and equipment (net of accumulated depreciation and amortization of $4,299 and $4,034 as of December 31, 2021 and 2020, respectively)		10,577		9,872
Deferred debits and other assets				
Regulatory assets		477		481
Investments		14		10
Prepaid pension asset		276		270
Other		44		69
Total deferred debits and other assets		811		830
Total assets	$	12,324	$	11,650

Baltimore Gas and Electric Company
Balance Sheets

	December 31,	
(In millions)	2021	2020
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 130	$ —
Long-term debt due within one year	250	300
Accounts payable	349	346
Accrued expenses	176	205
Payables to affiliates	48	61
Customer deposits	97	110
Regulatory liabilities	26	30
Other	48	91
Total current liabilities	1,124	1,143
Long-term debt	3,711	3,364
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,686	1,521
Asset retirement obligations	26	23
Non-pension postretirement benefits obligations	175	189
Regulatory liabilities	934	1,109
Other	98	104
Total deferred credits and other liabilities	2,919	2,946
Total liabilities	7,754	7,453
Commitments and contingencies		
Shareholder's equity		
Common stock (No par value, 0 shares[a] authorized, 0 shares[a] outstanding as of December 31, 2021 and 2020)	2,575	2,318
Retained earnings	1,995	1,879
Total shareholder's equity	4,570	4,197
Total liabilities and shareholder's equity	$ 12,324	$ 11,650

(a) In millions, shares round to zero. Number of shares is 1,500 authorized and 1,000 outstanding as of December 31, 2021 and 2020.

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, 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
Net income	—	408	408
Common stock dividends	—	(292)	(292)
Contributions from parent	257	—	257
Balance, December 31, 2021	$ 2,575	$ 1,995	$ 4,570

Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2021	2020	2019
Operating revenues			
Electric operating revenues	$ 4,769	$ 4,463	$ 4,639
Natural gas operating revenues	168	162	167
Revenues from alternative revenue programs	91	21	(14)
Operating revenues from affiliates	13	17	14
Total operating revenues	5,041	4,663	4,806
Operating expenses			
Purchased power	1,417	1,279	1,371
Purchased fuel	73	69	75
Purchased power from affiliates	367	366	352
Operating and maintenance	925	940	939
Operating and maintenance from affiliates	179	159	143
Depreciation and amortization	821	782	754
Taxes other than income taxes	458	450	450
Total operating expenses	4,240	4,045	4,084
Gain on sales of assets	—	11	—
Operating income	801	629	722
Other income and (deductions)			
Interest expense, net	(267)	(268)	(263)
Other, net	69	57	55
Total other income and (deductions)	(198)	(211)	(208)
Income before income taxes	603	418	514
Income taxes	42	(77)	38
Equity in earnings of unconsolidated affiliate	—	—	1
Net income	$ 561	$ 495	$ 477
Comprehensive income	$ 561	$ 495	$ 477

Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2021	2020	2019
Cash flows from operating activities			
Net income	$ 561	$ 495	$ 477
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	821	782	754
Deferred income taxes and amortization of investment tax credits	24	(97)	(7)
Other non-cash operating activities	(12)	103	161
Changes in assets and liabilities:			
Accounts receivable	(48)	(159)	(39)
Receivables from and payables to affiliates, net	6	3	3
Inventories	(16)	(6)	(27)
Accounts payable and accrued expenses	34	49	(17)
Income taxes	17	(25)	16
Pension and non-pension postretirement benefit contributions	(48)	(39)	(25)
Other assets and liabilities	(182)	(104)	(179)
Net cash flows provided by operating activities	1,157	1,002	1,117
Cash flows from investing activities			
Capital expenditures	(1,720)	(1,604)	(1,355)
Other investing activities	2	7	(3)
Net cash flows used in investing activities	(1,718)	(1,597)	(1,358)
Cash flows from financing activities			
Changes in short-term borrowings	100	160	154
Repayments of short-term borrowings with maturities greater than 90 days	—	—	(125)
Issuance of long-term debt	825	602	485
Retirement of long-term debt	(260)	(128)	(157)
Change in Exelon intercompany money pool	(14)	9	12
Distributions to member	(703)	(553)	(526)
Contributions from member	683	494	398
Other financing activities	(17)	(10)	(5)
Net cash flows provided by financing activities	614	574	236
Increase (decrease) in cash, restricted cash, and cash equivalents	53	(21)	(5)
Cash, restricted cash, and cash equivalents at beginning of period	160	181	186
Cash, restricted cash, and cash equivalents at end of period	$ 213	$ 160	$ 181
Supplemental cash flow information			
(Decrease) increase in capital expenditures not paid	$ (6)	$ 54	$ 2

Pepco Holdings LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2021		December 31, 2020	
ASSETS				
Current assets				
Cash and cash equivalents		$ 136		$ 111
Restricted cash and cash equivalents		77		39
Accounts receivable				
Customer accounts receivable	616		611	
Customer allowance for credit losses	(104)		(86)	
Customer accounts receivable, net		512		525
Other accounts receivable	283		260	
Other allowance for credit losses	(39)		(33)	
Other accounts receivable, net		244		227
Receivable from affiliates		2		8
Inventories, net				
Fossil fuel		11		6
Materials and supplies		209		198
Regulatory assets		432		440
Other		69		45
Total current assets		1,692		1,599
Property, plant, and equipment (net of accumulated depreciation and amortization of $2,108 and $1,811 as of December 31, 2021 and 2020, respectively)		16,498		15,377
Deferred debits and other assets				
Regulatory assets		1,794		1,933
Investments		145		140
Goodwill		4,005		4,005
Prepaid pension asset		344		365
Deferred income taxes		8		10
Other		258		307
Total deferred debits and other assets		6,554		6,760
Total assets(a)		$ 24,744		$ 23,736

Pepco Holdings LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2021	2020
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 468	$ 368
Long-term debt due within one year	399	347
Accounts payable	578	539
Accrued expenses	281	299
Payables to affiliates	104	104
Borrowings from Exelon intercompany money pool	7	21
Customer deposits	81	106
Regulatory liabilities	68	137
Unamortized energy contract liabilities	89	92
Other	171	141
Total current liabilities	2,246	2,154
Long-term debt	7,148	6,659
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,675	2,439
Asset retirement obligations	70	59
Non-pension postretirement benefit obligations	66	86
Regulatory liabilities	1,238	1,438
Unamortized energy contract liabilities	146	235
Other	570	622
Total deferred credits and other liabilities	4,765	4,879
Total liabilities[a]	14,159	13,692
Commitments and contingencies		
Member's equity		
Membership interest	10,795	10,112
Undistributed losses	(210)	(68)
Total member's equity	10,585	10,044
Total liabilities and member's equity	$ 24,744	$ 23,736

(a) PHI's consolidated total assets include $0 million and $18 million as of December 31, 2021 and 2020, respectively, of PHI's consolidated VIE that can only be used to settle the liabilities of the VIE. PHI's consolidated total liabilities include $0 million and $26 million as of December 31, 2021 and 2020, 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 Gains/(Losses)	Total Member's Equity
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
Net income	—	561	561
Distribution to member	—	(703)	(703)
Contributions from member	683	—	683
Balance, December 31, 2021	$ 10,795	$ (210)	$ 10,585

Potomac Electric Power Company
Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2021	2020	2019
Operating revenues			
Electric operating revenues	$ 2,216	$ 2,102	$ 2,258
Revenues from alternative revenue programs	53	40	(3)
Operating revenues from affiliates	5	7	5
Total operating revenues	2,274	2,149	2,260
Operating expenses			
Purchased power	353	324	401
Purchased power from affiliate	271	278	264
Operating and maintenance	258	248	273
Operating and maintenance from affiliates	213	205	209
Depreciation and amortization	403	377	374
Taxes other than income taxes	373	367	378
Total operating expenses	1,871	1,799	1,899
Gain on sales of assets	—	9	—
Operating income	403	359	361
Other income and (deductions)			
Interest expense, net	(140)	(138)	(133)
Other, net	48	38	31
Total other income and (deductions)	(92)	(100)	(102)
Income before income taxes	311	259	259
Income taxes	15	(7)	16
Net income	$ 296	$ 266	$ 243
Comprehensive income	$ 296	$ 266	$ 243

Potomac Electric Power Company
Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2021	2020	2019
Cash flows from operating activities			
Net income	$ 296	$ 266	$ 243
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	403	377	374
Deferred income taxes and amortization of investment tax credits	(8)	(46)	1
Other non-cash operating activities	(52)	(23)	56
Changes in assets and liabilities:			
Accounts receivable	(28)	(67)	(22)
Receivables from and payables to affiliates, net	6	(12)	5
Inventories	(8)	1	(19)
Accounts payable and accrued expenses	16	41	(39)
Income taxes	11	(1)	9
Pension and non-pension postretirement benefit contributions	(11)	(11)	(14)
Other assets and liabilities	(163)	(24)	(82)
Net cash flows provided by operating activities	462	501	512
Cash flows from investing activities			
Capital expenditures	(843)	(773)	(626)
Other investing activities	(1)	—	3
Net cash flows used in investing activities	(844)	(773)	(623)
Cash flows from financing activities			
Changes in short-term borrowings	140	(47)	42
Issuance of long-term debt	275	300	260
Retirement of long-term debt	—	(3)	(125)
Dividends paid on common stock	(268)	(232)	(213)
Contributions from parent	244	262	160
Other financing activities	(6)	(6)	(3)
Net cash flows provided by financing activities	385	274	121
Increase in cash, restricted cash, and cash equivalents	3	2	10
Cash, restricted cash, and cash equivalents at beginning of period	65	63	53
Cash, restricted cash, and cash equivalents at end of period	$ 68	$ 65	$ 63
Supplemental cash flow information			
Increase in capital expenditures not paid	$ 30	$ 1	$ 39

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Balance Sheets

(In millions)	December 31, 2021		December 31, 2020	
ASSETS				
Current assets				
Cash and cash equivalents	$	34	$	30
Restricted cash and cash equivalents		34		35
Accounts receivable				
Customer accounts receivable	277		279	
Customer allowance for credit losses	(37)		(32)	
Customer accounts receivable, net		240		247
Other accounts receivable	160		131	
Other allowance for credit losses	(16)		(13)	
Other accounts receivable, net		144		118
Receivables from affiliates		—		2
Inventories, net		119		111
Regulatory assets		213		214
Other		25		13
Total current assets		809		770
Property, plant, and equipment (net of accumulated depreciation and amortization of $3,875 and $3,697 as of December 31, 2021 and 2020, respectively)		8,104		7,456
Deferred debits and other assets				
Regulatory assets		532		570
Investments		120		115
Prepaid pension asset		279		284
Other		59		69
Total deferred debits and other assets		990		1,038
Total assets	$	9,903	$	9,264

Potomac Electric Power Company
Balance Sheets

(In millions)	December 31, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 175	$ 35
Long-term debt due within one year	313	3
Accounts payable	272	226
Accrued expenses	160	164
Payables to affiliates	59	55
Customer deposits	35	51
Regulatory liabilities	14	46
Merger related obligation	27	33
Other	55	61
Total current liabilities	1,110	674
Long-term debt	3,132	3,162
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,275	1,189
Asset retirement obligations	45	39
Non-pension postretirement benefit obligations	3	13
Regulatory liabilities	549	644
Other	314	340
Total deferred credits and other liabilities	2,186	2,225
Total liabilities	6,428	6,061
Commitments and contingencies		
Shareholder's equity		
Common stock ($0.01 par value, 200 shares authorized, 0 shares[(a)] outstanding as of December 31, 2021 and 2020)	2,302	2,058
Retained earnings	1,173	1,145
Total shareholder's equity	3,475	3,203
Total liabilities and shareholder's equity	$ 9,903	$ 9,264

(a) In millions, shares round to zero. Number of shares is 100 outstanding as of December 31, 2021 and 2020.

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, 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
Net income	—	296	296
Common stock dividends	—	(268)	(268)
Contributions from parent	244	—	244
Balance, December 31, 2021	$ 2,302	$ 1,173	$ 3,475

Delmarva Power & Light Company
Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2021	2020	2019
Operating revenues			
Electric operating revenues	$ 1,191	$ 1,107	$ 1,143
Natural gas operating revenues	168	162	167
Revenues from alternative revenue programs	14	(7)	(11)
Operating revenues from affiliates	7	9	7
Total operating revenues	1,380	1,271	1,306
Operating expenses			
Purchased power	387	359	381
Purchased fuel	73	69	75
Purchased power from affiliates	79	75	70
Operating and maintenance	183	208	171
Operating and maintenance from affiliates	162	153	152
Depreciation and amortization	210	191	184
Taxes other than income taxes	67	65	56
Total operating expenses	1,161	1,120	1,089
Operating income	219	151	217
Other income and (deductions)			
Interest expense, net	(61)	(61)	(61)
Other, net	12	10	13
Total other income and (deductions)	(49)	(51)	(48)
Income before income taxes	170	100	169
Income taxes	42	(25)	22
Net income	$ 128	$ 125	$ 147
Comprehensive income	$ 128	$ 125	$ 147

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2021	2020	2019
Cash flows from operating activities			
Net income	$ 128	$ 125	$ 147
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	210	191	184
Deferred income taxes and amortization of investment tax credits	39	(13)	(7)
Other non-cash operating activities	3	51	27
Changes in assets and liabilities:			
Accounts receivable	15	(34)	(5)
Receivables from and payables to affiliates, net	(3)	8	(5)
Inventories	(8)	(5)	(6)
Accounts payable and accrued expenses	16	4	3
Income taxes	13	(25)	12
Pension and non-pension postretirement benefit contributions	(1)	—	(1)
Other assets and liabilities	(27)	(30)	(55)
Net cash flows provided by operating activities	385	272	294
Cash flows from investing activities			
Capital expenditures	(429)	(424)	(348)
Other investing activities	4	(3)	1
Net cash flows used in investing activities	(425)	(427)	(347)
Cash flows from financing activities			
Changes in short-term borrowings	3	90	56
Issuance of long-term debt	125	178	75
Retirement of long-term debt	—	(80)	(12)
Dividends paid on common stock	(147)	(141)	(139)
Contributions from parent	120	112	63
Other financing activities	(5)	(2)	(1)
Net cash flows provided by financing activities	96	157	42
Increase (decrease) in cash and cash equivalents	56	2	(11)
Cash and cash equivalents at beginning of period	15	13	24
Cash and cash equivalents at end of period	$ 71	$ 15	$ 13
Supplemental cash flow information			
(Decrease) increase in capital expenditures not paid	$ (18)	$ 20	$ (4)

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Balance Sheets

(In millions)	December 31, 2021		December 31, 2020	
ASSETS				
Current assets				
Cash and cash equivalents	$	28	$	15
Restricted cash and cash equivalents		43		—
Accounts receivable				
Customer accounts receivable	149		176	
Customer allowance for credit losses	(18)		(22)	
Customer accounts receivable, net		131		154
Other accounts receivable	58		68	
Other allowance for credit losses	(8)		(9)	
Other accounts receivable, net		50		59
Receivables from affiliates		1		1
Inventories, net				
Fossil fuel		11		6
Materials and supplies		54		51
Prepaid utility taxes		20		11
Regulatory assets		68		58
Other		16		13
Total current assets		422		368
Property, plant, and equipment, (net of accumulated depreciation and amortization of $1,635 and $1,533 as of December 31, 2021 and 2020, respectively)		4,560		4,314
Deferred debits and other assets				
Regulatory assets		212		222
Prepaid pension asset		157		162
Other		61		74
Total deferred debits and other assets		430		458
Total assets	$	5,412	$	5,140

Delmarva Power & Light Company
Balance Sheets

(In millions)	December 31, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 149	$ 146
Long-term debt due within one year	83	82
Accounts payable	131	126
Accrued expenses	40	46
Payables to affiliates	33	36
Customer deposits	28	32
Regulatory liabilities	25	47
Other	59	20
Total current liabilities	548	535
Long-term debt	1,727	1,595
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	803	715
Asset retirement obligations	16	14
Non-pension postretirement benefit obligations	11	15
Regulatory liabilities	441	493
Other	89	97
Total deferred credits and other liabilities	1,360	1,334
Total liabilities	3,635	3,464
Commitments and contingencies		
Shareholder's equity		
Common stock ($2.25 par value, 0 shares(a) authorized, 0 shares(a) outstanding as of December 31, 2021 and 2020, respectively)	1,209	1,089
Retained earnings	568	587
Total shareholder's equity	1,777	1,676
Total liabilities and shareholder's equity	$ 5,412	$ 5,140

(a) In millions, shares round to zero. Number of shares is 1,000 authorized and 1,000 outstanding as of December 31, 2021 and 2020.

Delmarva Power & Light Company
Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
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
Net income	—	128	128
Common stock dividends	—	(147)	(147)
Contributions from parent	120	—	120
Balance, December 31, 2021	$ 1,209	$ 568	$ 1,777

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, 2021	2020	2019
Operating revenues			
Electric operating revenues	$ 1,362	$ 1,253	$ 1,237
Revenues from alternative revenue programs	24	(12)	—
Operating revenues from affiliates	2	4	3
Total operating revenues	1,388	1,245	1,240
Operating expenses			
Purchased power	677	596	589
Purchased power from affiliate	17	13	19
Operating and maintenance	179	192	187
Operating and maintenance from affiliates	141	134	133
Depreciation and amortization	179	180	157
Taxes other than income taxes	8	8	4
Total operating expenses	1,201	1,123	1,089
Gain on sales of assets	—	2	—
Operating income	187	124	151
Other income and (deductions)			
Interest expense, net	(58)	(59)	(58)
Other, net	4	6	6
Total other income and (deductions)	(54)	(53)	(52)
Income before income taxes	133	71	99
Income taxes	(13)	(41)	—
Net income	$ 146	$ 112	$ 99
Comprehensive income	$ 146	$ 112	$ 99

Atlantic City Electric Company and Subsidiary Company
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2021	2020	2019
Cash flows from operating activities			
Net income	$ 146	$ 112	$ 99
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	179	180	157
Deferred income taxes and amortization of investment tax credits	(15)	(37)	3
Other non-cash operating activities	—	36	22
Changes in assets and liabilities:			
Accounts receivable	(37)	(55)	(13)
Receivables from and payables to affiliates, net	4	6	(6)
Inventories	1	(3)	(1)
Accounts payable and accrued expenses	3	5	26
Income taxes	—	(1)	2
Pension and non-pension postretirement benefit contributions	(3)	(2)	(1)
Other assets and liabilities	17	(42)	(27)
Net cash flows provided by operating activities	295	199	261
Cash flows from investing activities			
Capital expenditures	(445)	(401)	(375)
Other investing activities	1	6	(1)
Net cash flows used in investing activities	(444)	(395)	(376)
Cash flows from financing activities			
Changes in short-term borrowings	(43)	117	56
Repayments of short-term borrowings with maturities greater than 90 days	—	—	(125)
Issuance of long-term debt	425	123	150
Retirement of long-term debt	(260)	(44)	(18)
Dividends paid on common stock	(288)	(114)	(124)
Contributions from parent	319	117	175
Other financing activities	(5)	(1)	(1)
Net cash flows provided by financing activities	148	198	113
(Decrease) increase in cash, restricted cash, and cash equivalents	(1)	2	(2)
Cash, restricted cash, and cash equivalents at beginning of period	30	28	30
Cash, restricted cash, and cash equivalents at end of period	$ 29	$ 30	$ 28
Supplemental cash flow information			
(Decrease) increase in capital expenditures not paid	$ (18)	$ 33	$ (29)

Atlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets

	December 31,			
(In millions)	2021		2020	
ASSETS				
Current assets				
Cash and cash equivalents	$	29	$	17
Restricted cash and cash equivalents		—		3
Accounts receivable				
Customer accounts receivable	190		156	
Customer allowance for credit losses	(49)		(32)	
Customer accounts receivable, net		141		124
Other accounts receivable	76		72	
Other allowance for credit losses	(15)		(11)	
Other accounts receivable, net		61		61
Receivables from affiliates		2		6
Inventories, net		36		37
Regulatory assets		61		75
Other		3		3
Total current assets		333		326
Property, plant, and equipment, (net of accumulated depreciation and amortization of $1,420 and $1,303 as of December 31, 2021 and 2020, respectively)		3,729		3,475
Deferred debits and other assets				
Regulatory assets		430		395
Prepaid pension asset		27		40
Other		37		50
Total deferred debits and other assets		494		485
Total assets[(a)]	$	4,556	$	4,286

Atlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets

(In millions)	December 31, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 144	$ 187
Long-term debt due within one year	3	261
Accounts payable	165	177
Accrued expenses	44	46
Payables to affiliates	31	31
Customer deposits	18	23
Regulatory liabilities	28	44
Other	12	11
Total current liabilities	445	780
Long-term debt	1,579	1,152
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	679	624
Non-pension postretirement benefit obligations	12	17
Regulatory liabilities	224	274
Other	49	48
Total deferred credits and other liabilities	964	963
Total liabilities(a)	2,988	2,895
Commitments and contingencies		
Shareholder's equity		
Common stock ($3 par value, 25 shares authorized, 9 shares outstanding as of December 31, 2021 and 2020)	1,590	1,271
Retained (deficit) earnings	(22)	120
Total shareholder's equity	1,568	1,391
Total liabilities and shareholder's equity	$ 4,556	$ 4,286

(a) ACE's consolidated assets include $0 million and $13 million as of December 31, 2021 and 2020, respectively, of ACE's consolidated VIE that can only be used to settle the liabilities of the VIE. ACE's consolidated liabilities include $0 million and $21 million as of December 31, 2021 and 2020, 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 (Deficit)	Total Shareholder's Equity
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
Net income	—	146	146
Common stock dividends	—	(288)	(288)
Contributions from parent	319	—	319
Balance, December 31, 2021	$ 1,590	$ (22)	$ 1,568

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)

As of December 31, 2021, Exelon was 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.

On February 21, 2021, Exelon's Board of Directors approved a plan to separate the Utility Registrants and Generation, creating two publicly traded companies. The separation was completed on February 1, 2022. See Note 26 – Separation of the Combined Notes to Consolidated Financial Statements for additional information.

Name of Registrant / Subsidiary	Business	Service Territories
Commonwealth Edison Company (registrant)	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 (registrant)	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 (registrant)	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 (registrant)	Utility services holding company engaged, through its reportable segments Pepco, DPL, and ACE	Service Territories of Pepco, DPL, and ACE
Potomac Electric Power Company (registrant)	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 (registrant)	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 (registrant)	Purchase and regulated retail sale of electricity	Portions of Southern New Jersey
	Transmission and distribution of electricity to retail customers	
Constellation Energy Generation, LLC (formerly Exelon Generation Company, LLC) (subsidiary)	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

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. The accounts of Generation are included within Exelon's Consolidated Financial Statements. For activities and disclosures associated with Generation included in the Notes to the Exelon Consolidated Financial Statements, Generation is specifically named. 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.

As of December 31, 2021 and 2020, Exelon owned 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 CRP, of which Generation holds a 51% interest. The remaining interests in the consolidated VIEs are included in noncontrolling interests on Exelon's Consolidated Balance Sheet. See Note 23 — Variable Interest Entities for additional information on VIEs. As of February 1, 2022, as a result of the completion of the separation, Exelon no longer owns any interest in Generation. See Note 26 — Separation for additional information.

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.

Management makes estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and accompanying notes, and the amounts of revenues and expenses reported during the periods covered by those financial statements and accompanying notes. As of December 31, 2021 and 2020, and through the date of this report, management assessed certain accounting matters that require consideration of forecasted financial information, including, but not limited to, allowance for credit losses and the carrying value of goodwill and other long-lived assets, in context with the information reasonably available and the unknown future impacts of COVID-19. The Registrants' future assessment of the magnitude and duration of COVID-19, as well as other factors, could result in material impacts to their consolidated financial statements in future reporting periods.

Use of Estimates (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 long-lived 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 (All Registrants)

For their regulated electric and gas operations, the 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. The 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, DEPSC, 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. The Registrants' 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, the 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 the Registrants' Consolidated Balance Sheets to align with the classification of the related deferred income tax balances.

The 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, DPL, and ACE 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, DCPSC, and/or NJBPU 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 taxes that are presented on a gross basis.

Leases (All Registrants)

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 the rate implicit in the lease whenever that is readily determinable or 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 that 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 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 that 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 the economic benefits. 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, 2021 and 2020, 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 and Generation project-specific nonrecourse financing structures for debt service and financing of operations of the underlying entities, in addition to the items listed below for the Utility Registrants.
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, 2021 and 2020, 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 17 — Debt and Credit Agreements and 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, like 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 in Exelon'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, PHI, and ACE)

Exelon accounts for its investments in and arrangements with VIEs based on the following specific requirements:

- qualitative assessment of factors determinant in whether it has a controlling financial interest,
- ongoing reconsideration of this assessment, and
- where it consolidates a VIE (as primary beneficiary), disclosure of (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)

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 measurement alternative 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, associated with the Regulatory Agreement Units are included in regulatory liabilities at Exelon, ComEd, and PECO and in Noncurrent receivables from affiliates at ComEd and PECO. Realized and unrealized gains and losses, net of tax, on NDT funds associated with the Non-Regulatory Agreement Units are included in earnings at Exelon. 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. 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 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.

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 capitalizes 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.

Nuclear Fuel (Exelon)

The cost of nuclear fuel is capitalized in Property, plant, and equipment and charged to Purchased power and fuel expense using the unit-of-production method. Any potential future SNF disposal fees will also be expensed through Purchased power and 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)

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. Except for the regulatory assets and liabilities discussed above, amortization is generally recorded to Depreciation and amortization in the Registrants’ Consolidated Statements of Operations and Comprehensive Income when the recovery period is more than one year.

See Note 3 — Regulatory Matters and Note 24 — Supplemental Financial Information for additional information regarding the amortization of the Utility Registrants' regulatory assets and Generation's nuclear fuel and ARC, respectively.

Asset Retirement Obligations (All Registrants)

The Registrants estimate and recognize a liability for their 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. The Utility Registrants update their AROs either annually or on a rotational basis at least once every three years, based on a risk profile, unless circumstances warrant more frequent updates. The updates factor in new cost estimates, credit-adjusted, risk-free rates (CARFR) and escalation rates, and the timing of cash flows. AROs are accreted throughout each year to reflect the time value of money for these present value obligations through 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 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 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 potentially impaired by comparing the undiscounted expected future cash flows to the carrying value when indicators of impairment exist. When the undiscounted cash flow analysis indicates a long-lived asset or asset group may not be recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset 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). Exelon regularly monitors and evaluates 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 Exelon holds an investment recognizes an impairment loss, Exelon 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). 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). Equity investments with readily determinable fair values are measured and recorded at fair value with any changes in fair value recorded in 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, 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 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 most of the derivatives serve as economic hedges, there are also derivatives entered into for proprietary trading purposes, subject to Exelon’s RMP, and changes in the fair value of those derivatives are recorded in revenue or expense 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. See Note 3 — Regulatory Matters and Note 16 — Derivative Financial Instruments for additional information.

As part of Generation's energy marketing business, Generation enters 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 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. See Note 16 — Derivative Financial Instruments for additional information.

Retirement Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and OPEB plans for substantially 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.

2. Mergers, Acquisitions, and Dispositions (Exelon)

CENG Put Option

Prior to August 6, 2021, Generation owned 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 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 terms of the Put Option Agreement, EDF had 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. The transaction required approval by FERC and the NYPSC, which approvals were received on July 30, 2020 and April 15, 2021, respectively. On August 6, 2021, Generation and EDF entered into a settlement agreement pursuant to which Generation purchased EDF's equity interest in CENG for a net purchase price of $885 million, which includes, among other things, an adjustment for EDF's share of the balance of the preferred distribution payable by CENG to Generation. The difference between the net purchase price and EDF's noncontrolling interest as of August 6, 2021 was recorded in Common stock in Exelon's Consolidated Balance Sheet. As a result of the transaction, Exelon recorded deferred tax liabilities of $290 million in Common stock in the Consolidated Balance Sheet. See Note 14 — Income Taxes for additional information.

The following table summarizes the effects of the changes in Generation's ownership interest in CENG in Exelon's Shareholders' Equity:

	For the Year Ended December 31, 2021
Net income attributable to Exelon's common shareholders	$ 1,706
Pre-tax increase in Exelon's common stock for purchase of EDF's 49.99% equity interest[a]	1,080
Decrease in Exelon's common stock due to deferred tax liabilities resulting from purchase of EDF's 49.99% equity interest[a]	(290)
Change from net income attributable to common stock and transfers from noncontrolling interest	$ 2,496

(a) Represents non-cash activity in Exelon’s consolidated financial statements.

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 MW of generation in operation or under construction across more than 600 sites across the United States. Generation will retain certain solar assets not included in this agreement, primarily Antelope Valley.

Completion of the transaction contemplated by the sale agreement was subject to the satisfaction of several closing conditions which were satisfied in the first quarter of 2021. The sale was completed on March 31, 2021 for a purchase price of $810 million. Exelon received cash proceeds of $675 million, net of $125 million long-term debt assumed by the buyer and certain working capital and other post-closing adjustments. Exelon recognized a pre-tax gain of $68 million which is included in Gain on sales of assets and businesses in the Consolidated Statements of Operations and Comprehensive Income.

See Note 17 — Debt and Credit Agreements for additional information on the SolGen nonrecourse debt included as part of the transaction.

Agreement for the Sale of a Generation Biomass Facility

On April 28, 2021, Generation and ReGenerate entered into a purchase agreement, under which ReGenerate agreed to purchase Generation’s interest in the Albany Green Energy biomass facility. As a result, in the second quarter of 2021, Exelon recorded a pre-tax impairment charge of $140 million in Operating and maintenance expense in the Consolidated Statement of Operations and Comprehensive Income. Completion of the transaction was subject to the satisfaction of various customary closing conditions which were satisfied in the second quarter of 2021. The sale was completed on June 30, 2021 for a net purchase price of $36 million.

Disposition of Oyster Creek

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 of 2019. The sale was completed on July 1, 2019. Exelon 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 the SNF until it 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.

3. Regulatory Matters (All Registrants)

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

Utility Regulatory Matters (All Registrants)

Distribution Base Rate Case Proceedings

The following tables show the completed and pending distribution base rate case proceedings in 2021.

Completed Distribution Base Rate Case Proceedings

Registrant/ Jurisdiction	Filing Date	Service	Requested Revenue Requirement (Decrease) Increase	Approved Revenue Requirement (Decrease) Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois[a]	April 16, 2020	Electric	$ (11)	$ (14)	8.38 %	December 9, 2020	January 1, 2021
	April 16, 2021	Electric	51	46	7.36 %	December 1, 2021	January 1, 2022
PECO - Pennsylvania	September 30, 2020	Natural Gas	69	29	10.24 %	June 22, 2021	July 1, 2021
	March 30, 2021	Electric	246	132	N/A[b]	November 18, 2021	January 1, 2022
BGE - Maryland[c]	May 15, 2020 (amended September 11, 2020)	Electric	203	140	9.50 %	December 16, 2020	January 1, 2021
		Natural Gas	108	74	9.65 %		
Pepco - District of Columbia[d]	May 30, 2019 (amended June 1, 2020)	Electric	136	109	9.275 %	June 8, 2021	July 1, 2021
Pepco - Maryland[e]	October 26, 2020 (amended March 31, 2021)	Electric	104	52	9.55 %	June 28, 2021	June 28, 2021
DPL - Delaware	March 6, 2020 (amended February 2, 2021)	Electric	23	14	9.60 %	September 15, 2021	October 6, 2020
ACE - New Jersey[f]	December 9, 2020 (amended February 26, 2021)	Electric	67	41	9.60 %	July 14, 2021	January 1, 2022

(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. See discussion of the Clean Energy Law below for details on the transition away from the electric distribution formula rate. 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 2021 approved revenue requirement reflects an increase of $50 million for the initial year revenue requirement for 2021 and a decrease of $64 million related to the annual reconciliation for 2019. The revenue requirement for 2021 and the revenue requirement for 2019 provide for a weighted average debt and equity return on distribution rate base of 6.28% inclusive of an allowed ROE of 8.38%, reflecting the monthly average yields for 30-year treasury bonds plus 580 basis points.

ComEd's 2022 approved revenue requirement above reflects an increase of $37 million for the initial year revenue requirement for 2022 and an increase of $9 million related to the annual reconciliation for 2020. The revenue requirement for 2022 provides for a weighted average debt and equity return on distribution rate base of 5.72% inclusive of an allowed ROE of 7.36%, reflecting the monthly average yields for 30-year treasury bonds plus 580 basis points. The reconciliation revenue requirement for 2020 provides for a weighted average debt and equity return on distribution rate base of 5.69%, inclusive of an allowed ROE of 7.29%, reflecting the monthly yields on 30-year treasury bonds plus 580 basis points less a performance metrics penalty of 7 basis points.

(b) The PECO electric base rate case proceeding was resolved through a settlement agreement, which did not specify an approved ROE.

(c) Reflects a three-year cumulative multi-year plan for 2021 through 2023. The MDPSC awarded BGE electric revenue requirement increases of $59 million, $39 million, and $42 million, before offsets, in 2021, 2022, and 2023, respectively, and natural gas revenue requirement increases of $53 million, $11 million, and $10 million, before offsets, in 2021, 2022, and 2023, respectively. BGE proposed to use certain tax benefits to fully offset the increases in 2021 and 2022 and partially offset the increase in 2023. However, the MDPSC utilized the tax benefits to fully offset the increases in 2021 and January 2022 such that customer rates remained unchanged. For the remainder of 2022, the MDPSC chose to offset only 25% of the cumulative 2021 and 2022 electric revenue requirement increases and 50% of the cumulative gas revenue requirement increases. Whether certain tax benefits will be used to offset the customer rate increases in 2023 has not been decided, and BGE cannot predict the outcome.

(d) Reflects a cumulative multi-year plan with 18-months remaining in 2021 through 2022. The DCPSC awarded Pepco electric incremental revenue requirement increases of $42 million and $67 million, before offsets, for the remainder of 2021 and 2022, respectively. However, the DCPSC utilized the acceleration of refunds for certain tax benefits along with other rate relief to partially offset the customer rate increases by $22 million and $40 million for the remainder of 2021 and 2022, respectively.

(e) Reflects a three-year cumulative multi-year plan for April 1, 2021 through March 31, 2024. The MDPSC awarded Pepco electric incremental revenue requirement increases of $21 million, $16 million, and $15 million, before offsets, for the 12-month periods ending March 31, 2022, 2023, and 2024, respectively. Pepco proposed to utilize certain tax benefits to fully offset the increase through 2023 and partially offset customer rate increases in 2024. However, the MDPSC only utilized the acceleration of refunds for certain tax benefits to fully offset the increases such that customer rates remain unchanged through March 31, 2022. On February 23, 2022, the MDPSC chose to offset 25% of the cumulative revenue requirement increase through March 31, 2023. Whether certain tax benefits will be used to offset the customer rate increases for the twelve months ended March 31, 2024 has not been decided, and Pepco cannot predict the outcome.

(f) Requested and approved increases are before New Jersey sales and use tax. The order allows ACE to retain approximately $11 million of certain tax benefits which resulted in a decrease to income tax expense in Exelon's, PHI's, and ACE's Consolidated Statements of Operations and Comprehensive Income in the third quarter of 2021.

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
DPL - Delaware	January 14, 2022	Natural Gas	$ 14	10.30 %	First quarter of 2023
DPL - Maryland[a]	September 1, 2021 (amended December 23, 2021)	Electric	27	10.10 %	First quarter of 2022

(a) On January 24, 2022, DPL filed a settlement agreement with the MDPSC. The settlement provides for a revenue requirement increase of $13 million. The 9.60% ROE in the agreement is solely for the purposes of calculating AFUDC and regulatory asset carrying costs. On February 15, 2021, the Chief Public Utility Law Judge issued a proposed order approving the settlement agreement without modification. The proposed order will become a final order of the MDPSC on March 2, 2022, subject to modification or reversal by the MDPSC.

Transmission Formula Rates

The Utility Registrants' transmission rates are each established based on a FERC-approved formula. ComEd, BGE, Pepco, DPL, and ACE are required to file an annual update to the FERC-approved formula on or before May 15, and PECO is required to file on or before May 31, with the resulting rates effective on June 1 of the same year. The annual update for ComEd 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 BGE, Pepco, DPL, and ACE 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 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, BGE, Pepco, DPL, and ACE also reconciles any differences between the actual costs and actual revenues for the calendar year (annual reconciliation).

For 2021, 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 Increase	Total Revenue Requirement Increase[b]	Allowed Return on Rate Base[c]	Allowed ROE[d]
ComEd	$ 33	$ 12	$ 45	8.20 %	11.50 %
PECO	(2)	26	24	7.37 %	10.35 %
BGE	38	27	65	7.35 %	10.50 %
Pepco	(9)	21	12	7.68 %	10.50 %
DPL	19	33	52	7.20 %	10.50 %
ACE	27	24	51	7.45 %	10.50 %

(a) All rates are effective June 1, 2021 - May 31, 2022, subject to review by interested parties pursuant to review protocols of each Utility Registrant's tariff.

(b) In 2020, ComEd, BGE, Pepco, DPL, and ACE's transmission revenue requirement included a one-time decrease in accordance with the April 24, 2020 settlement agreement related to excess deferred income taxes which now completed has resulted in an increase to the 2021 transmission revenue requirement. In 2020, PECO's transmission revenue requirement included a one-time decrease in accordance with the December 5, 2019 settlement agreement related to refunds which now completed has resulted in an increase to the 2021 transmission revenue requirement.

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

(d) As part of the FERC-approved settlements 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

Clean Energy Law (Exelon and ComEd). On September 15, 2021, the Illinois Public Act 102-0662 was signed into law by the Governor of Illinois (“Clean Energy Law”). The Clean Energy Law includes, among other features, (1) procurement of CMCs from qualifying nuclear-powered generating facilities, (2) a requirement to file a general rate case or a new four-year multi-year plan no later than January 20, 2023 to establish rates effective after ComEd’s existing performance-based distribution formula rate sunsets, (3) an extension of and certain adjustments to ComEd’s energy efficiency MWh savings goals, (4) revisions to the Illinois RPS requirements, including expanded charges for the procurement of RECs from wind and solar generation, (5) a requirement to accelerate amortization of ComEd’s unprotected excess deferred income taxes that ComEd was previously directed by the ICC to amortize using the average rate assumption method which equates to approximately 39.5 years, and (6) requirements that the ICC initiate and conduct various regulatory proceedings on subjects including ethics, spending, grid investments, and performance metrics. Regulatory or legal challenges regarding the validity or implementation of the Clean Energy Law are possible and Exelon and ComEd cannot reasonably predict the outcome of any such challenges.

Carbon Mitigation Credit

The Clean Energy Law establishes decarbonization requirements for Illinois as well as programs to support the retention and development of emissions-free sources of electricity. Among other things, the Clean Energy Law authorized the IPA to procure up to 54.5 million CMCs from qualifying nuclear plants for a five-year period beginning on June 1, 2022 through May 31, 2027. CMCs are credits for the carbon-free attributes of eligible nuclear power plants in PJM. The Byron, Dresden, and Braidwood nuclear plants located in Illinois participated in the CMC procurement process and were awarded contracts that commit each plant to operate through May 31, 2027. Pursuant to these contracts, ComEd will procure CMCs based upon the number of MWhs produced annually by each plant, subject to minimum performance requirements. The price to be paid for each CMC was established through a competitive bidding process that included consumer-protection measures that capped the maximum acceptable bid amount and a formula that reduces CMC prices by an energy price index, the base residual auction capacity price in the ComEd zone of PJM, and the monetized value of any federal tax credit or other subsidy if applicable. The consumer protection measures contained in the new law will result in net payments to ComEd ratepayers if the energy index, the capacity price and applicable federal tax credits or subsidy exceed the CMC contract price.

ComEd is required to purchase CMCs pursuant to these contracts and all its costs of doing so will be recovered through a new rider. That rider will provide for an annual reconciliation and true-up to actual costs incurred by ComEd to purchase CMCs, with any difference to be credited to or collected from ComEd's retail customers in subsequent periods.

See Note 7 — Early Plant Retirements for the impacts of the provisions above on the Illinois nuclear plants and Exelon's consolidated financial statements. The provisions do not impact ComEd's consolidated financial statements until 2022.

ComEd Electric Distribution Rates

The Clean Energy Law contains requirements associated with ComEd's transition away from the performance-based electric distribution formula rate. The law authorizing that rate setting process sunsets at the end of 2022. The Clean Energy Law, and tariffs adopted under it, governs both the remaining reconciliations of rates set under that formula process and requires ComEd to file in 2023 its choice of either a general rate case or a four-year multi-year plan to set rates that take effect in 2024.

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

If ComEd elects to file a multi-year plan, that plan would set rates for 2024 – 2027, based on forecasted revenue requirements and an ICC determined rate of return on rate base, including the cost of common equity. Each year of the multi-year plan is subject to after the fact ICC review and reconciliation of the plan's revenue requirement for that year with the actual costs that the ICC determines are prudently and reasonably incurred for that year. That reconciliation is subject to adjustment for certain expenses and, unless the plan is modified, to a 5% cap on increases in certain costs over the costs in the previously approved multi-year rate plan revenue requirement. ComEd would make its initial reconciliation filing in 2025, and the rate adjustments necessary to reconcile 2024 revenues to ComEd's actual 2024 costs incurred would take effect in January 2026 after the ICC's review. The ICC must also approve certain annual performance metrics, which can impose symmetrical performance adjustments in the total range of 20 to 60 basis points to ComEd's rate of return on common equity based on the extent to which ComEd achieved the annual performance goals. ComEd will recover from retail customers, subject to certain exceptions, the costs it incurs pursuant to the Clean Energy Law either through its electric distribution rate or other recovery mechanisms.

The Clean Energy Law, among other things, also requires ComEd's rates to include a decoupling mechanism to eliminate any impacts of weather or load from ComEd's electric distribution rate revenues. The Clean Energy Law also requires the ICC to initiate a docket to accelerate and fully credit to customers unprotected property related TCJA excess deferred income taxes no later than December 31, 2025.

Energy Efficiency

The Clean Energy Law extends ComEd's current cumulative annual energy efficiency MWh savings goals through 2040, adds expanded electrification measures to those goals, increases low-income commitments and adds a new performance adjustment to the energy efficiency formula rate. ComEd expects its annual spend to increase in 2022 through 2040 to achieve these energy efficiency MWh savings goals, which will be deferred as a separate regulatory asset that will be recovered through the energy efficiency formula rate over the weighted average useful life, as approved by the ICC, of the related energy efficiency measures.

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 2021, 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[(a)]	Approved ROE	Approval Date	Rate Effective Date
June 1, 2021	$ 54	$ 54	7.36 %	November 18, 2021	January 1, 2022

(a) ComEd's 2022 approved revenue requirement above reflects an increase of $55 million for the initial year revenue requirement for 2022 and a decrease of $1 million related to the annual reconciliation for 2020. The revenue requirement for 2022 provides for a weighted average debt and equity return on the energy efficiency regulatory asset and rate base of 5.72% inclusive of an allowed ROE of 7.36%, reflecting the monthly average yields for 30-year treasury bonds plus 580 basis points. The revenue requirement for the 2020 reconciliation year provides for a weighted average debt and equity return on the energy efficiency asset and rate base of 6.26% inclusive of an allowed ROE of 8.46%, which includes an upward performance adjustment that increased the ROE. The performance adjustment can either increase or decrease the ROE based upon the achievement of energy efficiency savings goals. See table below for ComEd's regulatory assets associated with its energy efficiency formula rate.

Maryland Regulatory Matters

Maryland Revenue Decoupling (Exelon, BGE, PHI, Pepco, and DPL). In 1998, the MDPSC approved natural gas monthly rate adjustments for BGE and in 2007, the MDPSC approved electric monthly rate adjustments for BGE and BSAs for Pepco and DPL, all of which are decoupling mechanisms. As a result of the decoupling mechanisms, certain Operating revenues from electric and natural gas distribution at BGE and Operating revenues from electric distribution at Pepco Maryland (see also District of Columbia Revenue Decoupling below for Pepco District of Columbia) and DPL are not impacted by abnormal weather or usage per customer. For BGE, Pepco, and DPL, the decoupling mechanism eliminates the impacts of abnormal weather or customer usage by recognizing revenues based on an authorized distribution amount per customer by customer class. Operating revenues from electric and natural gas distribution at BGE and Operating revenues from electric distribution at Pepco Maryland and DPL are, however, impacted by changes in the number of customers.

Maryland Order Directing the Distribution of Energy Assistance Funds (Exelon, BGE, PHI, Pepco, and DPL). On June 15, 2021, the MDPSC issued an order authorizing the disbursal of funds to utilities in accordance with Maryland COVID-19 relief legislation. Under this order, BGE, Pepco, and DPL received funds of $50 million, $12 million, and $8 million, respectively, in July 2021. The funds have been used to reduce or eliminate certain qualifying past-due residential customer receivables.

District of Columbia Regulatory Matters

District of Columbia Revenue Decoupling (Exelon, PHI, and Pepco). In 2009, the DCPSC approved a BSA, which is a decoupling mechanism. As a result of the decoupling mechanism, Operating revenues from electric distribution at Pepco District of Columbia (see also Maryland Revenue Decoupling above for Pepco Maryland) are not impacted by abnormal weather or usage per customer. The decoupling mechanism eliminates the impacts of abnormal weather or customer usage by recognizing revenues based on an authorized distribution amount per customer by customer class. Operating revenues from electric distribution at Pepco District of Columbia are, however, impacted by changes in the number of customers.

New Jersey Regulatory Matters

Conservation Incentive Program (CIP) (Exelon, PHI, and ACE). On September 25, 2020, ACE filed an application with the NJBPU as was required seeking approval to implement a portfolio of energy efficiency programs pursuant to New Jersey’s clean energy legislation. The filing included a request to implement a CIP that would eliminate the favorable and unfavorable impacts of weather and customer usage patterns on distribution revenues for most customers. The CIP compares current distribution revenues by customer class to approved target revenues established in ACE’s most recent distribution base rate case. The CIP is calculated annually and recovery is subject to certain conditions, including an earnings test and ceilings on customer rate increases.

On April 27, 2021, the NJBPU approved the settlement filed by ACE and the third parties to the proceeding. The approved settlement addresses all material aspects of ACE’s filing, including ACE’s ability to implement the CIP prospectively effective July 1, 2021. As a result of this decoupling mechanism, operating revenues will no longer be impacted by abnormal weather or usage for most customers. Starting in third quarter of 2021, ACE will record alternative revenue program revenues for its best estimate of the distribution revenue impacts resulting from future changes in CIP rates that it believes are probable of approval by the NJBPU in accordance with this mechanism.

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 consisted 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.

On July 14, 2021, the NJBPU approved the settlement filed by ACE and the third parties to the proceeding. The approved settlement addresses all material aspects of ACE's smart energy network deployment plan, including cost recovery of the investment costs, incremental O&M expenses, and the unrecovered balance of existing infrastructure through future distribution rates.

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 the Registrants as of December 31, 2021 and 2020:

December 31, 2021	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Regulatory assets								
Pension and OPEB	$ 2,409	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Pension and OPEB - merger related	893	—	—	—	—	—	—	—
Deferred income taxes	883	—	873	—	10	10	—	—
AMI programs - deployment costs	145	—	—	89	56	30	26	—
AMI programs - legacy meters	186	69	—	29	88	60	21	7
Electric distribution formula rate annual reconciliations	44	44	—	—	—	—	—	—
Electric distribution formula rate significant one-time events	104	104	—	—	—	—	—	—
Energy efficiency costs	1,181	1,181	—	—	—	—	—	—
Fair value of long-term debt	557	—	—	—	443	—	—	—
Fair value of PHI's unamortized energy contracts	236	—	—	—	236	—	—	—
Asset retirement obligations	145	99	21	19	6	5	—	1
MGP remediation costs	283	266	8	9	—	—	—	—
Renewable energy	219	219	—	—	—	—	—	—
Electric energy and natural gas costs	96	—	—	49	47	29	13	5
Transmission formula rate annual reconciliations	43	—	14	1	28	—	8	20
Energy efficiency and demand response programs	564	—	—	283	281	199	79	3
Under-recovered revenue decoupling	157	—	—	32	125	125	—	—
Removal costs	758	—	—	143	615	147	109	360
DC PLUG charge	70	—	—	—	70	70	—	—
Deferred storm costs	49	—	—	—	49	3	3	43
COVID-19	82	28	33	8	13	10	3	—
Under-recovered credit loss expense	89	60	—	—	29	—	—	29
Other	327	135	42	30	130	57	18	23
Total regulatory assets	9,520	2,205	991	692	2,226	745	280	491
Less: current portion	1,296	335	48	215	432	213	68	61
Total noncurrent regulatory assets	$ 8,224	$ 1,870	$ 943	$ 477	$ 1,794	$ 532	$ 212	$ 430

December 31, 2021	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory liabilities								
Deferred income taxes	$ 4,005	$ 2,105	$ —	$ 819	$ 1,081	$ 525	$ 354	$ 202
Nuclear decommissioning	3,357	2,760	597	—	—	—	—	—
Removal costs	1,694	1,541	—	39	114	20	94	—
Electric energy and natural gas costs	113	25	71	—	17	9	3	5
Transmission formula rate annual reconciliations	8	7	—	—	1	1	—	—
Renewable portfolio standards costs	500	500	—	—	—	—	—	—
Stranded costs	35	—	—	—	35	—	—	35
Other	292	6	61	102	58	8	15	10
Total regulatory liabilities	10,004	6,944	729	960	1,306	563	466	252
Less: current portion	376	185	94	26	68	14	25	28
Total noncurrent regulatory liabilities	$ 9,628	$ 6,759	$ 635	$ 934	$ 1,238	$ 549	$ 441	$ 224

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

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' and PHI's 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' and PHI's 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

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Deferred income taxes	Deferred income taxes that are recoverable or refundable through customer rates, primarily associated with accelerated depreciation, the equity component of AFUDC, and the effects of income tax rate changes, including those resulting from the TCJA. These amounts include transmission-related regulatory liabilities that require FERC approval separate from the transmission formula rate. See Transmission-Related Income Tax Regulatory Assets section above for additional information.	Over the period in which the related deferred income taxes reverse, which is generally based on the expected life of the underlying assets. For TCJA, generally refunded over the remaining depreciable life of the underlying assets, except in certain jurisdictions where the commissions have approved a shorter refund period for certain assets not subject to IRS normalization rules.	No
AMI programs - deployment costs	Installation and ongoing incremental 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 ACE - To be determined in next distribution rate case filed with NJBPU	BGE, Pepco, DPL - Yes ACE - Yes, on incremental costs of new smart meters
AMI programs - legacy meters	Early retirement costs of legacy meters.	ComEd - 2028 BGE - 2026 Pepco - 2027 DPL - 2030 ACE - To be determined in next distribution rate case filed with NJBPU	ComEd, Pepco (District of Columbia), DPL (Delaware), ACE - 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.	2023	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.	2025	Yes

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
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.	2032	Yes
Fair value of long-term debt	Represents the difference between the carrying value and fair value of long-term debt of BGE and PHI of $114 million and $443 million, respectively, as of December 31, 2021, and $120 million and $478 million, respectively, as of December 31, 2020, 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
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.	2023	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 - 2025 BGE - 2026 Pepco, DPL - 2036 ACE - 2031	BGE, Pepco, DPL, ACE - Yes PECO - Yes on capital investment recovered through this mechanism

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Under-recovered revenue decoupling	Electric and / or gas distribution costs recoverable from customers under decoupling mechanisms.	BGE - 2022 Pepco (Maryland) - $22 million - 2022 Pepco (District of Columbia) - $103 million: $66 million to be recovered via monthly surcharge by 2024; $37 million to be recovered via monthly surcharge, estimated to be fully recovered by 2028	BGE and Pepco - 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 refund mechanism filing with NJBPU	Stranded costs - Yes Overcollection - No
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.	2024	Portion of asset funded by Pepco- Yes

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
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 - $1 million - 2025; $2 million to be determined in pending distribution rate case filed with MDPSC ACE - $36 million - 2024; $7 million to be determined in next distribution rate case filed with NJBPU	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	Incremental credit losses and direct costs related to COVID-19 incurred primarily in 2020 at the Utility Registrants, partially offset by a decrease in travel costs at BGE, Pepco and DPL. Direct costs consisted primarily of costs to acquire personal protective equipment, costs for cleaning supplies and services, and costs to hire healthcare professionals to monitor the health of employees.	ComEd - 2025 BGE - 2025 PECO - 2024 Pepco (District of Columbia) - $8 million to be determined in next distribution rate case filed with DCPSC Pepco (Maryland) - $1 million - 2026; $1 million to be determined in next distribution rate case filed with MDPSC DPL (Maryland) - $1 million to be determined in pending distribution rate case filed with MDPSC DPL (Delaware) - $2 million to be determined in next distribution rate case filed with DEPSC	ComEd and BGE - Yes PECO, Pepco, and DPL - No

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Under-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 over a twelve-month period beginning in June of the following calendar year. ACE intends to recover from June through May of each respective year, subject to approval of the NJBPU.	ComEd - 2024 ACE - To be determined in next Societal Benefits Rider filing with 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.	$432 million to be determined in the ICC annual reconciliation for 2023 $68 million to be determined based on the LTRRPP developed by the IPA	No

Capitalized Ratemaking Amounts Not Recognized

The following table presents authorized amounts capitalized for ratemaking purposes related to earnings on shareholders' investment that are not recognized for financial reporting purposes in the Registrants' Consolidated Balance Sheets. These amounts will be recognized as revenues in the related Consolidated Statements of Operations and Comprehensive Income in the periods they are billable to the Utility Registrants' customers.

	Exelon	ComEd[(a)]	PECO	BGE[(b)]	PHI	Pepco[(c)]	DPL[(c)]	ACE
December 31, 2021	$ 43	$ 1	$ —	$ 37	$ 5	$ 3	$ 2	$ —
December 31, 2020	51	(1)	—	45	7	4	3	—

(a) Reflects ComEd's unrecognized equity returns/(losses) earned/(incurred) for ratemaking purposes on its electric distribution formula rate regulatory assets.
(b) BGE's authorized amounts capitalized for ratemaking purposes primarily relate to earnings on shareholders' investment on its AMI programs.
(c) Pepco's and DPL's authorized amounts capitalized for ratemaking purposes relate to earnings on shareholders' investment on their respective AMI Programs and Energy Efficiency and Demand Response Programs. The earnings on energy efficiency are on Pepco DC and DPL DE programs only.

Generation Regulatory Matters (Exelon)

Impacts of the February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages

Beginning on February 15, 2021, Generation's Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced outages as a result of extreme cold weather conditions. In addition, those weather conditions drove increased demand for service, dramatically increased wholesale power prices, and also increased gas prices in certain regions. In response to the high demand and significantly reduced total generation on the system, the PUCT directed ERCOT to use an administrative price cap of $9,000 per MWh during firm load shedding events.

The estimated impact to Exelon's Net Income for the year ended December 31, 2021 arising from these market and weather conditions was a reduction of approximately $800 million. The ultimate impact to Exelon's consolidated financial statements may be affected by a number of factors, including the impacts of customer and counterparty defaults and recoveries, any additional solutions to address the financial challenges caused by the event, and related litigation and contract disputes.

During February and March 2021, various parties with differing interests, including generators and retail providers, filed requests with the PUCT to void the PUCT’s orders setting prices at $9,000 per MWh during firm load shedding events. Other requests were made for the PUCT to enforce its order and reduce prices for 33 hours between February 18 and February 19 after firm load shedding ceased, and to cap ancillary services at $9,000 per MWh. On March 2, 2021, a third party filed a notice of appeal in the Court of Appeals for the Third District of Texas challenging the validity of the PUCT’s actions. Generation intervened in that appeal and filed its initial brief on June 2, 2021 and reply brief on November 5, 2021. On April 19, 2021, Generation filed a declaratory action and request for judicial review of the PUCT’s orders setting prices at $9,000 per MWh in District Court of Travis County, Texas. Generation subsequently requested that the District Court of Travis County, Texas stay its proceeding pending action by the Court of Appeals in the third party proceeding. On May 17, 2021, Generation amended its petition for declaratory action and request for judicial review pending in the District Court of Travis County, Texas. Exelon cannot reasonably predict the outcome of these proceedings or the potential financial statement impact.

Due to the event, a number of ERCOT market participants experienced bankruptcies or defaulted on payments to ERCOT, resulting in approximately a $3.0 billion payment shortfall in collections, which is allocated to the remaining ERCOT market participants. As of December 31, 2021, Exelon has recorded Generation's estimated portion of this obligation, net of legislative solutions, of approximately $17 million on a discounted basis, which is to be paid over a term of 83 years. ERCOT rules historically have limited recovery of default from market participants to $2.5 million per month market-wide. In February 2021, the PUCT gave ERCOT discretion to disregard those rules, but ERCOT has declined to exercise that discretion as to the imposition of uplift charges. On March 8, 2021, a third party filed a notice of appeal in the Court of Appeals for the Third District of Texas challenging the validity of the PUCT's order to ERCOT in February 2021. Generation intervened in that appeal and filed its initial brief on July 7, 2021. The case has been stayed until March 3, 2022 to afford time for the PUCT to respond to ERCOT's November 18, 2021 request that the PUCT withdraw its February 2021 order. On May 7, 2021, Generation filed a declaratory action and request for judicial review of the PUCT's order in the District Court of Travis County, Texas. Generation subsequently requested that the District Court of Travis County, Texas stay its proceeding pending action by the Court of Appeals in the third party proceeding. Exelon cannot reasonably predict the outcome of these proceedings or the potential financial statement impact.

Additionally, several legislative proposals were introduced in the Texas legislature during February and March 2021 concerning the amount, timing and allocation of recovery of the $3.0 billion shortfall, as well as recovery of other costs associated with the PUCT's directive to set prices at $9,000 per MWh. Two of these proposals were enacted into law in June 2021 and establish financing mechanisms that ERCOT and certain market participants can utilize to fund amounts owed to ERCOT. Generation participated in proceedings before the PUCT addressing the proposed allocation of the $2.1 billion in securitized funds for reliability and ancillary service charges over $9,000 per MWh. In September 2021, Generation entered into a settlement agreement and stipulation to resolve the allocation issues. The PUCT approved the settlement agreement and stipulation on October 13, 2021.

In addition, other legislative proposals were introduced in the Texas legislature during February and March 2021 addressing cold-weather preparation for power plants and natural gas production and transportation infrastructure and the market structure for reliability services. The Texas legislature addressed these proposals by enacting a bill with a broad set of market reforms that, among other things, directed the PUCT to establish weatherization standards for electric generators within six months of enactment and gave the PUCT authority to impose administrative penalties if the new proposed standards, once adopted, are not met. On October 21, 2021, the PUCT adopted a rule change requiring generators by December 1, 2021 to complete a number of specified winter readiness preparations and to submit to ERCOT a report describing and certifying the completion of those preparations. The PUCT described these requirements as the first phase of its actions with respect to winter preparedness, which Generation completed timely, and will be followed by a second phase consisting of a year-round set of weather preparedness standards to be informed by a weather study conducted by ERCOT and submitted to the PUCT on December 15, 2021.

The legislation also directs the PUCT to evaluate whether additional ancillary services are needed for reliability in the ERCOT power region to provide adequate incentives for dispatchable generation. Throughout 2021, Exelon and others submitted various proposals to the PUCT with respect to a range of potential market reforms, including the implementation of additional ancillary service products as well as changes to the high system-wide offer cap and operating reserve demand curve, which remain pending. On December 2, 2021, the PUCT reduced ERCOT's high system-wide offer cap to $5,000 per MWh.

In February 2021, more than 70 local distribution companies (LDCs) and natural gas pipelines in multiple states throughout the mid-continent region, where Generation serves natural gas customers, issued operational flow orders (OFOs), curtailments or other limitations on natural gas transportation or use to manage the operational integrity of the applicable LDC or pipeline system. When in effect, gas transportation or use above these limitations is subject to significant penalties according to the applicable LDCs' and natural gas pipelines' tariffs. Gas transportation and supply in many states became restricted due to wells freezing and pipeline compression disruption, while demand was increasing due to the extreme cold temperatures, resulting in extremely high natural gas prices. Due to the extraordinary circumstances, many LDCs and natural gas pipelines have either voluntarily waived or have sought applicable regulatory approvals to waive the tariff penalties associated with the extreme weather event. During March 2021, three natural gas pipelines filed individual petitions with FERC requesting approval to waive OFO penalties. Generation also filed motions in March 2021 to intervene and filed comments in support of these FERC waiver requests. On March 25, 2021, FERC issued an order on one of the petitions approving a pipeline's request for a limited waiver of penalties for February 15, 2021. On April 23, 2021, Generation and several other entities filed a request at FERC for rehearing of this order which was denied on May 24, 2021. Generation and the other entities filed an appeal of the rehearing of the order with the U.S. Court of Appeals for the D.C. Circuit on July 21, 2021. Additionally, Generation and the other entities filed a complaint requesting that FERC expand the order to include additional days of the weather event in February, from February 16 through February 19, 2021. On October 21, 2021, FERC denied the complaint finding that a pipeline has the discretion whether to waive penalties under its tariff, and on December 6, 2021 the related D.C. Circuit petition for review was withdrawn. During April 2021, FERC issued orders on the remaining petitions approving the requests to waive the penalties. During May 2021, an LDC filed a motion with the Kansas Corporation Commission (KCC) requesting the KCC to grant a waiver from the tariff and allow the LDC to reduce the amounts assessed by permitting the removal of a multiplier from the penalty calculation. On January 20, 2022, a unanimous settlement that was filed with the KCC that amended previously filed October 8, 2021 and November 30, 2021 nonunanimous settlements that, if approved, would resolve this matter. Exelon cannot predict the outcome of the KCC proceeding.

Illinois Regulatory Matters

Clean Energy Law. See Clean Energy Law above for additional information related to Generation. See Note 7 – Early Plant Retirements for additional information on Generation's Illinois nuclear plants.

New Jersey Regulatory Matters

New Jersey Clean Energy Legislation. On May 23, 2018, New Jersey enacted legislation that established a ZEC program that provides compensation for nuclear plants that demonstrate to the NJBPU that they meet certain requirements, including that they make a significant contribution to air quality in the state and that their revenues are insufficient to cover their costs and risks. Under the legislation, the NJBPU will issue ZECs to qualifying nuclear power plants and the electric distribution utilities in New Jersey, including ACE, will be required to purchase those ZECs. On April 18, 2019, the NJBPU approved the award of ZECs to Salem 1 and Salem 2. Upon approval, Generation began recognizing revenue for the sale of New Jersey ZECs in the month they are generated. On March 19, 2021, a three-judge panel of the Superior Court of New Jersey Appellate Division unanimously affirmed the NJBPU's April 2019 order awarding ZECs for the first eligibility period. On April 8, 2021, New Jersey Rate Counsel filed a notice asking the New Jersey Supreme Court to hear the appeal of the Superior Court's order. On July 9, 2021, the New Jersey Supreme Court declined to hear the appeal. On October 1, 2020, PSEG and Generation filed applications seeking ZECs for the second eligibility period (June 2022 through May 2025). On April 27, 2021, the NJBPU approved the award of ZECs to Salem 1 and Salem 2 for the second eligibility period. On May 11, 2021, the New Jersey Rate Counsel appealed the April 27, 2021 decision to the Superior Court of New Jersey Appellate Division. Briefing on the appeal is expected to conclude in the first half of 2022. Exelon cannot reasonably predict the outcome of this proceeding.

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 nuclear facilities in PJM and NYISO that are currently receiving state-supported compensation, for carbon-free attributes, an expanded MOPR would require exclusion of such 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 expanded the breadth and scope of PJM’s MOPR, which became effective as of PJM’s capacity auction for the 2022-2023 planning year. 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.

A number of parties, including Exelon, have filed petitions for review of FERC's orders in this proceeding, which remain pending before the Court of Appeals for the Seventh Circuit.

As a result, the MOPR applied in the capacity auction for the 2022-23 planning year to Generation's owned or jointly owned nuclear plants in those states receiving a benefit under the Illinois ZES, and the New Jersey ZEC program. The MOPR prevented Quad Cities from clearing in that capacity auction.

At the direction of the PJM Board of Managers, PJM and its stakeholders developed further MOPR reforms to ensure that the capacity market rules respect and accommodate state resource preferences such as the ZEC programs. PJM filed related tariff revisions at FERC on July 30, 2021 and, on September 29, 2021, PJM's proposed MOPR reforms became effective by operation of law. Under the new tariff provisions, the MOPR will no longer apply to any of Generation’s owned or jointly owned nuclear plants. Requests for rehearing of FERC’s notice establishing the effective date for PJM’s proposed market reforms were filed in October 2021 and denied by operation of law on November 4, 2021. Several parties have filed petitions for review of FERC's orders in this proceeding, which remain pending before the Court of Appeals for the Third Circuit. Exelon is strenuously opposing these appeals. Exelon cannot predict the outcome of this proceeding.

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 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.

Operating License Renewals

Conowingo Hydroelectric Project. On August 29, 2012, Generation submitted an application to FERC for a new license for the Conowingo Hydroelectric Project (Conowingo). In connection with Generation's efforts to obtain a water quality certification pursuant to Section 401 of the Clean Water Act (401 Certification) from MDE for Conowingo, Generation had been working with MDE and other stakeholders to resolve water quality licensing issues, including: (1) water quality, (2) fish habitat, and (3) sediment.

On April 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 contained 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.

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 were modifications to river flows to improve aquatic habitat, eel passage improvements, and initiatives to support rare, threatened and endangered wildlife.

On March 19, 2021, FERC issued a new 50-year license for Conowingo, effective March 1, 2021. FERC adopted the Proposed License Articles into the new license only making modifications it deemed necessary to allow FERC to enforce the Proposed License Articles. Consistent with the Offer of Settlement, FERC found that MDE waived its 401 Certification and pursuant to a separate agreement with MDE (MDE Settlement), Generation agreed to implement additional environmental protection, mitigation, and enhancement measures over the 50-year term of the new license. These measures address mussel restoration and other ecological and water quality matters, among other commitments. On April 19, 2021, a few environmental groups filed with FERC a petition for rehearing requesting that FERC reconsider the issuance of the new Conowingo license, which was denied by operation of law on May 20, 2021. On June 17, 2021, the petitioners appealed FERC's ruling to the U.S. Court of Appeals for the D.C. Circuit. On July 15, 2021, FERC issued an order addressing the arguments raised on rehearing, affirming the determinations of its March 19, 2021 order.

The financial impact of the DOI and MDE Settlements and other anticipated license commitments are 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.

Peach Bottom Units 2 and 3. On March 6, 2020, the NRC approved a second 20-year license renewal for Peach Bottom Units 2 and 3. 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)	Sales of power and other energy-related commodities to wholesale and retail customers across multiple geographic regions through Generation's customer-facing business.	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)	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)	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 (The 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 (The 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 is able to collect over the entire term of the contract. In such cases, Exelon estimates 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 not material as of December 31, 2021 and 2020. The Utility Registrants do not incur any material costs to obtain or fulfill contracts with customers.

Contract Balances (All Registrants)

Contract Assets

Exelon 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. Exelon records contract assets and contract receivables in Other current assets and Customer accounts receivable, net, respectively, in the Consolidated Balance Sheets.

The following table provides a rollforward of the contract assets reflected in Exelon's Consolidated Balance Sheets. The Utility Registrants do not have any contract assets.

	Exelon
Balance as of December 31, 2019	$ 174
Amounts reclassified to receivables	(86)
Revenues recognized	68
Contract assets reclassified as held-for-sale	(12)
Balance as of December 31, 2020	144
Amounts reclassified to receivables	(59)
Revenues recognized	52
Amounts previously held-for-sale	12
Balance as of December 31, 2021	$ 149

Contract Liabilities

The Registrants record contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. The Registrants record contract liabilities in Other current liabilities and Other noncurrent liabilities in the Registrants' Consolidated Balance Sheets.

For Generation, these contract liabilities primarily relate to upfront consideration received or due for equipment service plans and the Illinois ZEC program that introduces a cap on the total consideration to be received by Generation. 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, PHI's, Pepco's, DPL's, and ACE'S Consolidated Balance Sheets. As of December 31, 2021, 2020, and 2019, ComEd's, PECO's, and BGE's contract liabilities were not material.

	Exelon	PHI	Pepco	DPL	ACE
Balance as of December 31, 2018	$ 27	$ —	$ —	$ —	$ —
Consideration received or due	94	—	—	—	—
Revenues recognized	(88)	—	—	—	—
Balance as of December 31, 2019	33	—	—	—	—
Consideration received or due	219	122	98	12	12
Revenues recognized	(98)	(4)	(4)	—	—
Contract liabilities reclassified as held-for-sale	(3)	—	—	—	—
Balance as of December 31, 2020	151	118	94	12	12
Consideration received or due	97	—	—	—	—
Revenues recognized	(110)	(9)	(7)	(1)	(1)
Amounts previously held-for-sale	3	—	—	—	—
Balance as of December 31, 2021	$ 141	$ 109	$ 87	$ 11	$ 11

The following table reflects revenues recognized in the years ended December 31, 2021, 2020 and 2019, which were included in contract liabilities at December 31, 2020, 2019, and 2018, respectively:

	2021	2020	2019
Exelon	$ 40	$ 27	$ 18
PHI	9	—	—
Pepco	7	—	—
DPL	1	—	—
ACE	1	—	—

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, 2021. This disclosure only includes contracts for which the total consideration is fixed and determinable at contract inception. The average contract term varies by customer type and commodity but ranges from one month to several years.

This disclosure excludes Generation's power and gas sales contracts as they contain variable volumes and/or variable pricing. This disclosure 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.

	2022	2023	2024	2025	2026 and thereafter	Total
Exelon	$ 194	$ 70	$ 38	$ 31	$ 155	$ 488
PHI	8	8	6	5	82	109
Pepco	6	6	5	5	65	87
DPL	1	1	—	—	9	11
ACE	1	1	1	—	8	11

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 includes five reportable segments for Generation 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 the reportable segments of Generation is the integrated management of Generation's 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 the five reportable segments of Generation 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 that covers a majority of the state 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 CODM evaluates the performance of Generation’s electric business activities and allocates resources based on Revenues Net of Purchased Power and Fuel Expense (RNF). Management 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. The CODM does 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 reportable segment information to the respective information in the Exelon consolidated financial statements for the years ended December 31, 2021, 2020, and 2019 is as follows:

	ComEd	PECO	BGE	PHI	Generation	Other[(a)]	Intersegment Eliminations	Exelon
Operating revenues[(b)]:								
2021								
Competitive businesses electric revenues	$ —	$ —	$ —	$ —	$ 16,290	$ —	$ (1,171)	$ 15,119
Competitive businesses natural gas revenues	—	—	—	—	3,379	—		3,379
Competitive businesses other revenues	—	—	—	—	(20)	—	(11)	(31)
Rate-regulated electric revenues	6,406	2,659	2,505	4,860	—	—	(78)	16,352
Rate-regulated natural gas revenues	—	539	836	168	—	—	(15)	1,528
Shared service and other revenues	—	—	—	13	—	2,213	(2,226)	—
Total operating revenues	$ 6,406	$ 3,198	$ 3,341	$ 5,041	$ 19,649	$ 2,213	$ (3,501)	$ 36,347
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	$ 5,904	$ 3,058	$ 3,098	$ 4,663	$ 17,603	$ 2,035	$ (3,322)	$ 33,039

	ComEd	PECO	BGE	PHI	Generation	Other(a)	Intersegment Eliminations	Exelon
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	$ 5,747	$ 3,100	$ 3,106	$ 4,806	$ 18,924	$ 1,921	$ (3,166)	$ 34,438
Intersegment revenues(c):								
2021	$ 41	$ 21	$ 31	$ 13	$ 1,188	$ 2,203	$ (3,497)	$ —
2020	37	9	20	17	1,211	2,024	(3,314)	4
2019	30	6	26	14	1,172	1,913	(3,159)	2
Depreciation and amortization:								
2021	$ 1,205	$ 348	$ 591	$ 821	$ 3,003	$ 67	$ 1	$ 6,036
2020	1,133	347	550	782	2,123	79	—	5,014
2019	1,033	333	502	754	1,535	95	—	4,252
Operating expenses:								
2021	$ 5,151	$ 2,547	$ 2,860	$ 4,240	$ 20,196	$ 2,242	$ (3,411)	$ 33,825
2020	4,950	2,512	2,598	4,045	17,358	2,047	(3,270)	30,240
2019	4,580	2,388	2,574	4,084	17,628	1,996	(3,154)	30,096
Interest expense, net:								
2021	$ 389	$ 161	$ 138	$ 267	$ 297	$ 320	$ (1)	$ 1,571
2020	382	147	133	268	357	351	(3)	1,635
2019	359	136	121	263	429	308	—	1,616
Income (loss) before income taxes:								
2021	$ 914	$ 516	$ 373	$ 603	$ 152	$ (351)	$ 1	$ 2,208
2020	615	417	390	418	836	(343)	—	2,333
2019	851	593	439	514	1,917	(327)	(2)	3,985
Income taxes:								
2021	$ 172	$ 12	$ (35)	$ 42	$ 225	$ (46)	$ —	$ 370
2020	177	(30)	41	(77)	249	13	—	373
2019	163	65	79	38	516	(87)	—	774
Net income (loss):								
2021	$ 742	$ 504	$ 408	$ 561	$ (83)	$ (304)	$ 1	$ 1,829
2020	438	447	349	495	579	(354)	—	1,954

	ComEd	PECO	BGE	PHI	Generation	Other[a]	Intersegment Eliminations	Exelon
2019	688	528	360	477	1,217	(240)	(2)	3,028
Capital expenditures:								
2021	$ 2,387	$ 1,240	$ 1,226	$ 1,720	$ 1,329	$ 79	$ —	$ 7,981
2020	2,217	1,147	1,247	1,604	1,747	86	—	8,048
2019	1,915	939	1,145	1,355	1,845	49	—	7,248
Total assets:								
2021	$ 36,470	$ 13,824	$12,324	$ 24,744	$ 48,086	$ 7,727	$ (10,162)	$133,013
2020	34,466	12,531	11,650	23,736	48,094	9,005	(10,165)	129,317

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

(b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 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]:						
2021						
Rate-regulated electric revenues	$ 2,274	$ 1,212	$ 1,388	$ —	$ (14)	$ 4,860
Rate-regulated natural gas revenues	—	168	—	—	—	168
Shared service and other revenues	—	—	—	379	(366)	13
Total operating revenues	$ 2,274	$ 1,380	$ 1,388	$ 379	$ (380)	$ 5,041
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
Intersegment revenues[c]:						
2021	$ 5	$ 7	$ 2	$ 380	$ (381)	$ 13
2020	7	9	4	372	(375)	17
2019	5	7	3	396	(397)	14
Depreciation and amortization:						
2021	$ 403	$ 210	$ 179	$ 29	$ —	$ 821
2020	377	191	180	34	—	782
2019	374	184	157	39	—	754
Operating expenses:						
2021	$ 1,871	$ 1,161	$ 1,201	$ 388	$ (381)	$ 4,240
2020	1,799	1,120	1,123	378	(375)	4,045
2019	1,899	1,089	1,089	403	(396)	4,084
Interest expense, net:						
2021	$ 140	$ 61	$ 58	$ 8	$ —	$ 267
2020	138	61	59	10	—	268
2019	133	61	58	10	1	263
Income (loss) before income taxes:						
2021	$ 311	$ 170	$ 133	$ (11)	$ —	$ 603
2020	259	100	71	(12)	—	418
2019	259	169	99	(13)	—	514
Income taxes:						
2021	$ 15	$ 42	$ (13)	$ (2)	$ —	$ 42
2020	(7)	(25)	(41)	(4)	—	(77)
2019	16	22	—	—	—	38

	Pepco	DPL	ACE	Other[a]	Intersegment Eliminations	PHI
Net income (loss):						
2021	$ 296	$ 128	$ 146	$ (9)	$ —	$ 561
2020	266	125	112	(8)	—	495
2019	243	147	99	(12)	—	477
Capital expenditures:						
2021	$ 843	$ 429	$ 445	$ 3	$ —	$ 1,720
2020	773	424	401	6	—	1,604
2019	626	348	375	6	—	1,355
Total assets:						
2021	$ 9,903	$ 5,412	$ 4,556	$ 4,933	$ (60)	$ 24,744
2020	9,264	5,140	4,286	5,079	(33)	23,736

(a) Other primarily includes PHI's corporate operations, shared service entities, and other financing and investment activities.
(b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 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.

The following tables disaggregate the 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):

	2021				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 4,381	$ 183	$ 4,564	$ 20	$ 4,584
Midwest	4,265	(205)	4,060	—	4,060
New York	1,633	(57)	1,576	(1)	1,575
ERCOT	896	276	1,172	9	1,181
Other Power Regions	3,937	981	4,918	(28)	4,890
Total Competitive Businesses Electric Revenues	$ 15,112	$ 1,178	$ 16,290	$ —	$ 16,290
Competitive Businesses Natural Gas Revenues	1,777	1,602	3,379	—	3,379
Competitive Businesses Other Revenues(c)	365	(385)	(20)	—	(20)
Total Generation Consolidated Operating Revenues	$ 17,254	$ 2,395	$ 19,649	$ —	$ 19,649

	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

(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 losses of $633 million, gains of $110 million and losses of $4 million for the years ended December 31, 2021, 2020, and 2019, respectively, and the elimination of intersegment revenues.

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

	2021			2020			2019		
	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	$ 2,247	$ 17	$2,264	$ 2,174	$ 30	$2,204	$ 2,637	$ 18	$2,655
Midwest	2,717	—	2,717	2,902	—	2,902	2,994	(32)	2,962
New York	1,151	10	1,161	983	14	997	1,081	13	1,094
ERCOT	(668)	(157)	(825)	407	19	426	338	(30)	308
Other Power Regions	984	(93)	891	759	(94)	665	694	(74)	620
Total RNF for Reportable Segments	$ 6,431	$ (223)	$6,208	$ 7,225	$ (31)	$7,194	$ 7,744	$ (105)	$7,639
Other[b]	1,055	223	1,278	793	31	824	324	105	429
Total Generation RNF	$ 7,486	$ —	$7,486	$ 8,018	$ —	$8,018	$ 8,068	$ —	$8,068

(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 $565 million and $295 million and losses of $215 million for the years ended December 31, 2021, 2020, and 2019, respectively;
- accelerated nuclear fuel amortization associated with the announced early plant retirements as discussed in Note 7 - Early Plant Retirements of $148 million, $60 million, and $13 million in for the years ended December 31, 2021, 2020, and 2019, respectively; and
- the elimination of intersegment RNF.

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

	2021						
Revenues from contracts with customers	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Rate-regulated electric revenues							
Residential	$ 3,233	$ 1,704	$ 1,375	$ 2,441	$ 1,003	$ 694	$ 744
Small commercial & industrial	1,571	422	267	521	135	193	193
Large commercial & industrial	559	243	459	1,123	844	94	185
Public authorities & electric railroads	45	31	27	58	31	14	13
Other[(a)]	926	229	371	634	205	201	229
Total rate-regulated electric revenues[(b)]	$ 6,334	$ 2,629	$ 2,499	$ 4,777	$ 2,218	$ 1,196	$ 1,364
Rate-regulated natural gas revenues							
Residential	$ —	$ 372	$ 518	$ 97	$ —	$ 97	$ —
Small commercial & industrial	—	136	83	42	—	42	—
Large commercial & industrial	—	—	147	7	—	7	—
Transportation	—	24	—	14	—	14	—
Other[(c)]	—	7	68	8	—	8	—
Total rate-regulated natural gas revenues[(d)]	$ —	$ 539	$ 816	$ 168	$ —	$ 168	$ —
Total rate-regulated revenues from contracts with customers	$ 6,334	$ 3,168	$ 3,315	$ 4,945	$ 2,218	$ 1,364	$ 1,364
Other revenues							
Revenues from alternative revenue programs	$ 42	$ 26	$ 12	$ 91	$ 53	$ 14	$ 24
Other rate-regulated electric revenues[(e)]	30	4	11	5	3	2	—
Other rate-regulated natural gas revenues[(e)]	—	—	3	—	—	—	—
Total other revenues	$ 72	$ 30	$ 26	$ 96	$ 56	$ 16	$ 24
Total rate-regulated revenues for reportable segments	$ 6,406	$ 3,198	$ 3,341	$ 5,041	$ 2,274	$ 1,380	$ 1,388

	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

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

(b) Includes operating revenues from affiliates in 2021, 2020, and 2019 respectively of:
- $41 million, $37 million, and $30 million at ComEd
- $20 million, $8 million, and $5 million at PECO
- $13 million, $10 million, and $8 million at BGE
- $13 million, $17 million, and $14 million at PHI
- $5 million, $7 million, and $5 million at Pepco
- $7 million, $9 million, and $7 million at DPL
- $2 million, $4 million, and $3 million at ACE

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

(d) Includes operating revenues from affiliates in 2021, 2020, and 2019 respectively of:
- $1 million, $1 million, and $1 million at PECO
- $18 million, $10 million, and $18 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 tables present the rollforward of Allowance for Credit Losses on Customer Accounts Receivable.

	Year Ended December 31, 2021							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of December 31, 2020	$ 366	$ 97	$ 116	$ 35	$ 86	$ 32	$ 22	$ 32
Plus: Current period provision for expected credit losses[a]	126	21	23	15	37	13	6	18
Less: Write-offs, net of recoveries[b][c]	117	45	34	12	19	8	10	1
Balance as of December 31, 2021	$ 375	$ 73	$ 105	$ 38	$ 104	$ 37	$ 18	$ 49

	Year Ended December 31, 2020							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of December 31, 2019	$ 243	$ 59	$ 55	$ 12	$ 37	$ 13	$ 11	$ 13
Plus: Current period provision for expected credit losses[d]	248	62	79	30	64	24	15	25
Less: Write-offs, net of recoveries[c]	69	24	18	7	15	5	4	6
Less: Sale of customer accounts receivable[e]	56	—	—	—	—	—	—	—
Balance as of December 31, 2020	$ 366	$ 97	$ 116	$ 35	$ 86	$ 32	$ 22	$ 32

(a) For Exelon, the increase primarily relates to the impacts of the February 2021 extreme cold weather event. See Note 3 — Regulatory Matters for additional information. For the Utility Registrants, the increase is primarily a result of increased aging of receivables.

(b) For ComEd, PECO and DPL, the increase in 2021 is primarily related to the termination of the moratorium which, beginning in March 2020, prevented customer disconnections for non-payment. With disconnection activities restarting in 2021, write-offs of aging accounts receivable increased throughout the year.

(c) Recoveries were not material to the Registrants.

(d) 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.

(e) See below for additional information on the sale of customer accounts receivable in the second quarter of 2020.

The following tables present the rollforward of Allowance for Credit Losses on Other Accounts Receivable.

	Year Ended December 31, 2021							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of December 31, 2020	$ 71	$ 21	$ 8	$ 9	$ 33	$ 13	$ 9	$ 11
Plus: Current period provision for expected credit losses	15	(2)	3	4	6	3	(1)	4
Less: Write-offs, net of recoveries[(a)]	10	2	4	4	—	—	—	—
Balance as of December 31, 2021	$ 76	$ 17	$ 7	$ 9	$ 39	$ 16	$ 8	$ 15

	Year Ended December 31, 2020							
	Exelon	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, 2021 and 2020.

	Unbilled customer revenues[a]							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2021	$ 1,120	$ 240	$ 161	$ 171	$ 175	$ 82	$ 53	$ 40
December 31, 2020	998	218	147	197	178	87	62	29

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

Sales of Customer Accounts Receivable (Exelon)

On April 8, 2020, NER, a bankruptcy remote, special purpose entity, which is wholly-owned by Generation, entered into a revolving accounts receivable financing arrangement with a number of financial institutions and a commercial paper conduit (the Purchasers) to sell certain customer accounts receivable (the Facility). The Facility had a maximum funding limit of $750 million and was scheduled to expire on April 7, 2021, unless renewed by the mutual consent of the parties in accordance with its terms. The Facility was renewed on March 29, 2021. The Facility term was extended through March 29, 2024, unless further renewed by the mutual consent of the parties, and the maximum funding limit was increased to $900 million. Under the Facility, NER may sell eligible short-term customer accounts receivable to the Purchasers in exchange for cash and subordinated interest. The transfers are reported as sales of receivables in Exelon’s 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 in Exelon’s Consolidated Balance Sheets.

The Facility requires the balance of eligible receivables to be maintained at or above the balance of cash proceeds received from the Purchasers. To the extent the eligible receivables decrease below such balance, Generation is required to repay cash to the Purchasers. When eligible receivables exceed cash proceeds, Generation has the ability to increase the cash received up to the maximum funding limit. These cash inflows and outflows impact the DPP.

On April 8, 2020, Exelon 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.

During the first quarter of 2021, Exelon received additional cash of $250 million from the Purchasers for the remaining available funding in the Facility.

Additionally, during the first quarter of 2021, Exelon received cash of approximately $150 million from the Purchasers in connection with the increased funding limit at the time of the Facility renewal.

During the second quarter of 2021, Exelon returned cash of $50 million to the Purchasers due to the eligible receivables decreasing temporarily. Subsequently, in the second quarter, Exelon received cash of $50 million from the Purchasers as a result of an increase in the eligible receivable balance. The $50 million cash outflow and inflow is included in the Collection of DPP line in Cash flows from investing activities in Exelon’s Consolidated Statement of Cash Flows.

The following table summarizes the impact of the sale of certain receivables:

	As of December 31,	
	2021	2020
Derecognized receivables transferred at fair value	$ 1,265	$ 1,139
Cash proceeds received	900	500
DPP	365	639

	For the Year Ended December 31,	
	2021	2020
Loss on sale of receivables[a]	$ 36	$ 30

(a) Reflected in Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income.

	For the Year Ended December 31,	
	2021	2020
Proceeds from new transfers[a]	$ 6,095	$ 2,816
Cash collections received on DPP and reinvested in the Facility[b]	3,502	3,771
Cash collections reinvested in the Facility	9,597	6,587

(a) Customer accounts receivable sold into the Facility were $9,747 million and $6,608 million for the years ended December 31, 2021 and December 31, 2020, respectively.

(b) Does not include the $400 million in cash proceeds received from the Purchasers in the first quarter of 2021.

The 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. Exelon did not record a servicing asset or liability as the servicing fees were immaterial.

Exelon recognizes the cash proceeds received upon sale in Net cash provided by operating activities in the Consolidated Statements of Cash Flows. The collection and reinvestment of DPP is recognized in Net cash provided by investing activities in the Consolidated Statements 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)

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. 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 other purchases and sales of customer and other accounts receivable activity related to Generation is eliminated upon consolidation in Exelon's Consolidated Financial Statements. The following tables present the total receivables purchased and sold.

	Year Ended December 31, 2021							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Total receivables purchased	$ 3,817	$ 1,031	$ 1,041	$ 687	$ 1,081	$ 660	$ 217	$ 204
Total receivables sold	124	—	—	—	—	—	—	—
Related party transactions:								
Receivables purchased from Generation	—	1	1	21	—	—	—	—

	Year Ended December 31, 2020							
	Exelon	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	—	—	—	—	—	—	—
Related party transactions:								
Receivables purchased from Generation	—	34	67	79	72	51	13	8

7. Early Plant Retirements (Exelon)

Nuclear Generation

On August 27, 2020, Generation announced that it intended to permanently cease generation operations at Byron in September 2021 and at Dresden in November 2021. Neither of these nuclear plants cleared in PJM’s capacity auction for the 2022-2023 planning year held in May 2021. Generation’s Braidwood and LaSalle nuclear plants in Illinois did clear in the capacity auction, but were also showing increased signs of economic distress.

On September 15, 2021, the Illinois Public Act 102-0662 was signed into law by the Governor of Illinois (“Clean Energy Law”). The Clean Energy Law is designed to achieve 100% carbon-free power by 2045 to enable the state’s transition to a clean energy economy. Among other things, the Clean Energy Law authorized the IPA to procure up to 54.5 million CMCs from qualifying nuclear plants for a five-year period beginning on June 1, 2022 through May 31, 2027. CMCs are credits for the carbon-free attributes of eligible nuclear power plants in PJM. The Byron, Dresden, and Braidwood nuclear plants located in Illinois participated in the CMC procurement process and were awarded contracts that commit each plant to operate through May 31, 2027. See Note 3 — Regulatory Matters for additional information. Following enactment of the legislation, Generation announced on September 15, 2021, that it has reversed the previous decision to retire Byron and Dresden given the opportunity for additional revenue under the Clean Energy Law. In addition, Generation no longer considers the Braidwood or LaSalle nuclear plants to be at risk for premature retirement.

As a result of the decision to early retire Byron and Dresden, Exelon recognized certain one-time charges in the third and fourth quarters of 2020 related to materials and supplies inventory reserve adjustments, employee-related costs including severance benefit costs, and construction work-in-progress impairments, among other items. In addition, there were 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.

In the third quarter of 2021, Exelon reversed $81 million of severance benefit costs and $13 million of other one-time charges initially recorded in Operating and maintenance expense in the third and fourth quarters of 2020 associated with the early retirements. In addition, the expected economic useful life for both facilities was updated to 2044 and 2046 for Byron Units 1 and 2, respectively, and to 2029 and 2031 for Dresden Units 2 and 3, respectively, the end of the respective NRC operating license for each unit. Depreciation was therefore adjusted beginning September 15, 2021, to reflect these extended useful life estimates. See Note 10 — Asset Retirement Obligations for additional detail on changes to the nuclear decommissioning ARO balances resulting from the initial decision and subsequent reversal of the decision to early retire Byron and Dresden.

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, Generation announced that it would permanently cease generation operations at TMI. On September 20, 2019, TMI permanently ceased generation operations.

The total impact for the years ended December 31, 2021, 2020, and 2019 in Exelon's Consolidated Statements of Operations and Comprehensive Income resulting from the initial decision and subsequent reversal of the decision to early retire Byron and Dresden, and decision to early retire TMI is summarized in the table below.

Income statement expense (pre-tax)	**2021**[a]	**2020**[a]	**2019**[b]
Depreciation and amortization			
Accelerated depreciation[c]	$ 1,805	$ 895	$ 216
Accelerated nuclear fuel amortization	148	60	13
Operating and maintenance			
One-time charges	(94)	255	—
Other charges[d]	9	34	(53)
Contractual offset[e]	(451)	(364)	—
Total	$ 1,417	$ 880	$ 176

(a) Reflects expense for Byron and Dresden.
(b) Reflects expense for TMI.
(c) Includes the accelerated depreciation of plant assets including any ARC.
(d) For 2020 and 2019, reflects the net impacts associated with the remeasurement of the ARO. See Note 10 – Asset Retirement Obligations for additional information.
(e) Reflects contractual offset for ARO accretion, ARC depreciation, ARO remeasurement, and excludes any changes in earnings in the NDT funds. Decommissioning-related impacts were not offset for the Byron units starting in the second quarter of 2021 due to the inability to recognize a regulatory asset at ComEd. With the September 15, 2021 reversal of the previous decision to retire Byron, Generation resumed contractual offset for Byron as of that date. Based on the regulatory agreement with the ICC, decommissioning-related activities are offset in Exelon's Consolidated Statements of Operations and Comprehensive Income as long as the net cumulative decommissioning-related activities result in a regulatory liability at ComEd. The offset resulted in an equal adjustment to the regulatory liabilities at ComEd. See Note 10 — Asset Retirement Obligations for additional information.

Other Generation

In March 2018, Generation notified ISO-NE of its plans to early retire, among other assets, the Mystic Generating Station's units 8 and 9 (Mystic 8 and 9) absent regulatory reforms to properly value reliability and regional fuel security. Thereafter, ISO-NE identified Mystic 8 and 9 as being needed to ensure fuel security for the region and entered into a cost of service agreement with these two units for the period between June 1, 2022 - May 31, 2024. The agreement was approved by the FERC in December 2018.

On June 10, 2020, Generation filed a complaint with FERC against ISO-NE stating that ISO-NE failed to follow its tariff with respect to its evaluation of Mystic 8 and 9 for transmission security for the 2024 to 2025 Capacity Commitment Period and that the modifications that ISO-NE made to its unfiled planning procedures to avoid retaining Mystic 8 and 9 should have been filed with FERC for approval. On August 17, 2020, FERC issued an order denying the complaint. As a result, on August 20, 2020, Generation announced it will permanently cease generation operations at Mystic 8 and 9 at the expiration of the cost of service commitment in May 2024.

As a result of the decision to early retire Mystic 8 and 9, Exelon 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 recorded incremental Depreciation and amortization expense of $41 million and $26 million for the years ended December 31, 2021 and 2020, respectively. 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, 2021 and 2020:

Asset Category	Exelon[a]	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2021								
Electric—transmission and distribution	$ 64,771	$ 31,077	$ 10,076	$ 9,352	$ 16,062	$ 10,798	$ 4,957	$ 4,882
Electric—generation	29,912	—	—	—	—	—	—	—
Gas—transportation and distribution	7,429	—	3,339	3,712	646	—	806	—
Common—electric and gas	2,335	—	1,005	1,224	201	—	180	—
Nuclear fuel[b]	5,166	—	—	—	—	—	—	—
Construction work in progress	4,097	918	620	554	1,590	1,118	229	242
Other property, plant, and equipment[c]	827	99	41	34	107	63	23	25
Total property, plant, and equipment	114,537	32,094	15,081	14,876	18,606	11,979	6,195	5,149
Less: accumulated depreciation[d]	30,318	6,099	3,964	4,299	2,108	3,875	1,635	1,420
Property, plant, and equipment, net	$ 84,219	$ 25,995	$ 11,117	$ 10,577	$ 16,498	$ 8,104	$ 4,560	$ 3,729
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	—	—	—	—	—	—	—
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[b]	5,399	—	—	—	—	—	—	—
Construction work in progress	3,576	799	474	627	1,174	824	163	182
Other property, plant and equipment[c]	762	59	34	29	108	65	23	28
Total property, plant and equipment	109,311	30,229	14,024	13,906	17,188	11,153	5,847	4,778
Less: accumulated depreciation[d]	26,727	5,672	3,843	4,034	1,811	3,697	1,533	1,303
Property, plant, and equipment, net	$ 82,584	$ 24,557	$ 10,181	$ 9,872	$ 15,377	$ 7,456	$ 4,314	$ 3,475

(a) As of December 31, 2021, includes $19,612 million of Property, plant, and equipment, net related to Generation.

(b) Includes nuclear fuel that is in the fabrication and installation phase of $859 million and $939 million as of December 31, 2021 and 2020, respectively.

(c) Primarily composed of land and non-utility property.

(d) At Exelon, includes accumulated amortization of nuclear fuel in the reactor core of $2,765 million and $2,774 million as of December 31, 2021 and 2020, respectively.

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

	Average Service Life (years)							
Asset Category	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Electric - transmission and distribution	5-80	5-80	5-70	5-80	5-75	5-75	5-70	5-65
Electric - generation	1-52	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gas - transportation and distribution	5-80	N/A	5-70	5-80	5-75	N/A	5-75	N/A
Common - electric and gas	4-75	N/A	5-55	4-50	5-75	N/A	5-75	N/A
Nuclear fuel	1-8	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other property, plant, and equipment	1-61	32-50	50	20-50	3-50	33-50	8-50	13-15

Depreciation provisions are based on the estimated useful lives of the stations, which corresponds with the term of the NRC operating licenses for the nuclear units. 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. On September 15, 2021, Generation updated the expected useful lives for Byron and Dresden to reflect the end of the available NRC operating license for each unit. See Note 3 — Regulatory Matters for additional information regarding license renewal and Note 7 — Early Plant Retirements for additional information on the impacts related to Byron, Dresden, and Mystic.

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	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
December 31, 2021								
Electric—transmission and distribution	2.81 %	2.94 %	2.28 %	2.80 %	2.87 %	2.56 %	2.86 %	3.21 %
Electric—generation	8.67 %	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gas—transportation and distribution	2.13 %	N/A	1.84 %	2.54 %	1.47 %	N/A	1.47 %	N/A
Common—electric and gas	7.31 %	N/A	6.34 %	7.88 %	8.33 %	N/A	8.69 %	N/A
December 31, 2020								
Electric—transmission and distribution	2.79 %	2.95 %	2.31 %	2.69 %	2.81 %	2.53 %	2.85 %	3.08 %
Electric—generation	6.11 %	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gas—transportation and distribution	2.14 %	N/A	1.85 %	2.56 %	1.50 %	N/A	1.50 %	N/A
Common—electric and gas	7.01 %	N/A	6.39 %	7.45 %	7.36 %	N/A	6.72 %	N/A
December 31, 2019								
Electric—transmission and distribution	2.80 %	2.99 %	2.36 %	2.60 %	2.77 %	2.47 %	2.86 %	2.94 %
Electric—generation	4.35 %	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gas—transportation and distribution	2.04 %	N/A	1.89 %	2.30 %	1.55 %	N/A	1.55 %	N/A
Common—electric and gas	7.37 %	N/A	6.06 %	8.30 %	8.25 %	N/A	6.24 %	N/A

Capitalized Interest and AFUDC

The following table summarizes capitalized interest and credits to AFUDC by year:

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2021								
Capitalized interest	$ 16	$ —	$ —	$ —	$ —	$ —	$ —	$ —
AFUDC debt and equity	189	47	34	36	72	59	8	5
December 31, 2020								
Capitalized interest	$ 22	$ —	$ —	$ —	$ —	$ —	$ —	$ —
AFUDC debt and equity	150	42	23	30	55	42	6	7
December 31, 2019								
Capitalized interest	$ 24	$ —	$ —	$ —	$ —	$ —	$ —	$ —
AFUDC debt and equity	132	32	17	29	54	39	6	9

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, PECO, DPL, and ACE)

Exelon's, PECO's, DPL's, and ACE's material undivided ownership interests in jointly owned electric plants and transmission facilities as of December 31, 2021 and 2020 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 as of December 31, 2021:					
Plant in service	$ 1,211	$ 1,515	$ 756	$ 1,002	$ 103
Accumulated depreciation	715	628	299	222	55
Construction work in progress	11	12	20	41	—
Exelon's share as of 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	—

(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, 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, 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 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)

Generation has a legal obligation to decommission its nuclear power plants following permanent cessation of operations. To estimate its decommissioning obligations 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 AROs 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 in Property, plant, and equipment in Exelon's Consolidated Balance Sheets. If the ARO decreases for a Non-Regulatory Agreement unit without any remaining ARC, the corresponding change is recorded as a decrease in Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income.

The following table provides a rollforward of the nuclear decommissioning AROs reflected in Exelon's Consolidated Balance Sheets from December 31, 2019 to December 31, 2021:

Nuclear decommissioning AROs as of December 31, 2019	$ 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 AROs as of December 31, 2020[(a)]	11,922
Net increase due to changes in, and timing of, estimated future cash flows	324
Accretion expense	503
Costs incurred related to decommissioning plants	(73)
Nuclear decommissioning AROs as of December 31, 2021[(a)]	$ 12,676

(a) Includes $72 million and $80 million as the current portion of the ARO as of December 31, 2021 and 2020, respectively, which is included in Other current liabilities in Exelon's Consolidated Balance Sheets.

The net $324 million increase in the ARO during 2021 for changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments throughout the year. These adjustments primarily include:

- An increase of approximately $550 million for updated cost escalation rates, primarily for labor and energy, and a decrease in discount rates.
- An increase of approximately $90 million due to revisions to assumed retirement dates for several nuclear plants.
- A net decrease of approximately $170 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 reversal of the decision to early retire the plants. See Note 7 — Early Plant Retirements for additional information.
- A net decrease of approximately $150 million due to lower estimated decommissioning costs resulting from the completion of updated cost studies for seven nuclear plants.

The 2021 ARO updates resulted in a decrease of $51 million in Operating and maintenance expense for the year ended December 31, 2021 in Exelon's Consolidated Statement of Operations and Comprehensive Income.

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 resulting from the completion of updated cost studies primarily for two nuclear plants.

The 2020 ARO updates resulted in an increase of $60 million in Operating and maintenance expense for the year ended December 31, 2020 in Exelon's Consolidated Statement of Operations and Comprehensive Income.

NDT Funds

NDT funds have been established for each generation station nuclear unit to satisfy Generation's nuclear decommissioning obligations, as required by the NRC, and withdrawals from these funds for reasons other than to pay for decommissioning are restricted pursuant to NRC requirements until all decommissioning activities have been completed. 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, through regulated rates for decommissioning the former PECO nuclear plants, and these collections are scheduled through the operating lives of these 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. 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, are generally 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 former PECO nuclear plants where, through PECO, Generation has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for those units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC that limits collection of 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 former 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, certain conditions pertaining to NDT funds apply 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 as defined in the agreement or 50% of any excess funds in the trust funds above the amounts required for decommissioning (including SNF management and site restoration) 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.

The key criteria and assumptions used by Generation to determine the ARO and to forecast the target growth in the NDT funds as of December 31, 2021 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 SNF maintenance and storage subsequent to ceasing operations and until DOE acceptance, and disposal of certain LLRW); (3) as applicable, the consideration of multiple scenarios where decommissioning and site restoration activities are completed under possible scenarios ranging from 10 to 70 years after the cessation of plant operations or the end of the current licensed operating life; (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 5.5% to 6.3% (as compared to a historical 5-year annual average pre-tax return of approximately 10.2%).

As of December 31, 2021 and 2020, Exelon had NDT funds totaling $16,064 million and $14,599 million, respectively. The NDT funds also include $126 million and $134 million for the current portion of the NDT funds as of December 31, 2021 and 2020, respectively, which are included in Other current assets in Exelon'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 in Exelon’s Consolidated Statements of Operations and Comprehensive Income and are recorded by the corresponding regulated utility as a component of the intercompany and regulatory balances in the balance sheet.

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 excess funds to PECO customers (on an aggregate basis for all seven units), decommissioning-related activities are generally offset in Exelon’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 in the Consolidated Statement of Operations and Comprehensive Income results in an adjustment to the regulatory liabilities or regulatory assets and an equal noncurrent affiliate receivable from or payable to Generation at PECO.

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, decommissioning-related activities are offset in the Consolidated Statements of Operations and Comprehensive Income which results in an adjustment to the regulatory liabilities and noncurrent receivables from Generation at ComEd. 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 for that unit would not be offset. During the second and third quarter of 2021, a pre-tax charge of $53 million and $140 million, respectively, was recorded in Exelon’s Consolidated Statement of Operations and Comprehensive Income for decommissioning-related activities that were not offset for the Byron units due to contractual offset being temporarily suspended. With Generation’s September 15, 2021 reversal of the previous decision to retire Byron and the corresponding adjustment to the ARO for Byron discussed previously, Generation resumed contractual offset for Byron as of that date.

As of December 31, 2021, decommissioning-related activities for all of the former ComEd units, except for Zion (see Zion Station Decommissioning below), are currently offset in Exelon's Consolidated Statements of Operations and Comprehensive Income.

The decommissioning-related activities related to the Non-Regulatory Agreement Units are reflected in Exelon's Consolidated Statements of Operations and Comprehensive Income.

See Note 3 — Regulatory Matters for additional information regarding regulatory liabilities at ComEd and PECO.

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 back to Generation, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal, and complete all remaining decommissioning activities associated with the SNF dry storage facility.

Generation had retained its obligation for the SNF upon transfer of the NRC license to Generation 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, 2021, the ARO associated with Zion's SNF storage facility is $140 million and the NDT funds available to fund this obligation are $65 million.

Non-Nuclear Asset Retirement Obligations (All Registrants)

The Utility Registrants have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. In addition, Exelon has AROs for Generation's 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. 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 December 31, 2019 to December 31, 2021:

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Non-nuclear AROs as of December 31, 2019	$ 460	$ 129	$ 28	$ 23	$ 57	$ 41	$ 12	$ 4
Net increase (decrease) due to changes in, and timing of, estimated future cash flows	7	—	2	1	1	(3)	2	2
Development projects	1	—	—	—	—	—	—	—
Accretion expense[(a)]	16	1	1	1	1	1	—	—
Asset divestitures	(4)	—	—	—	—	—	—	—
Payments	(9)	(1)	(2)	(2)	—	—	—	—
AROs reclassified to liabilities held for sale	(10)	—	—	—	—	—	—	—
Non-nuclear AROs as of December 31, 2020	461	129	29	23	59	39	14	6
Net increase due to changes in, and timing of, estimated future cash flows	31	15	—	2	10	5	2	3
Accretion expense[(a)]	18	4	1	1	1	1	—	—
Asset divestitures	(19)	—	—	—	—	—	—	—
Payments	(11)	(2)	(1)	—	—	—	—	—
AROs previously held for sale	10	—	—	—	—	—	—	—
Non-nuclear AROs as of December 31, 2021	$ 490	$ 146	$ 29	$ 26	$ 70	$ 45	$ 16	$ 9

(a) For ComEd, PECO, BGE, PHI, and Pepco, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulatory treatment.

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, 2021. Exelon, ComEd, PECO, and BGE did not have material finance leases in 2021, 2020, or in 2019. PHI, Pepco, DPL, and ACE also did not have material finance leases in 2019.

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Contracted generation	●							
Real estate	●	●	●	●	●	●	●	●
Vehicles and equipment	●	●	●	●	●	●	●	●

(in years)	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Remaining lease terms	1-84	1-3	1-12	1-84	1-10	1-10	1-10	1-7
Options to extend the term	1-30	5	N/A	N/A	3-30	5	3-30	5
Options to terminate within	1-11	1	N/A	1	N/A	N/A	N/A	N/A

The components of operating lease costs were as follows:

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the year ended December 31, 2021								
Operating lease costs	$ 245	$ 3	$ —	$ 30	$ 43	$ 10	$ 12	$ 6
Variable lease costs	175	1	—	1	1	—	—	—
Short-term lease costs	—	—	—	—	—	—	—	—
Total lease costs[a]	$ 420	$ 4	$ —	$ 31	$ 44	$ 10	$ 12	$ 6
For the year ended December 31, 2020								
Operating lease costs	$ 292	$ 3	$ 1	$ 33	$ 46	$ 11	$ 13	$ 6
Variable lease costs	241	1	—	1	2	1	1	—
Short-term lease costs	2	—	—	—	—	—	—	—
Total lease costs[a]	$ 535	$ 4	$ 1	$ 34	$ 48	$ 12	$ 14	$ 6
For the year ended December 31, 2019								
Operating lease costs	$ 320	$ 3	$ 1	$ 33	$ 48	$ 12	$ 14	$ 7
Variable lease costs	300	2	—	2	6	2	2	1
Short-term lease costs	19	—	—	—	—	—	—	—
Total lease costs[a]	$ 639	$ 5	$ 1	$ 35	$ 54	$ 14	$ 16	$ 8

(a) Excludes sublease income recorded at Exelon, PHI, and DPL of $48 million, $4 million, and $4 million, respectively, for the year ended December 31, 2021, $48 million, $4 million, and $4 million, respectively, for the year ended December 31, 2020, and $51 million, $7 million, and $7 million, respectively, for the year ended December 31, 2019.

PHI, Pepco, DPL, and ACE recorded finance lease costs of $13 million, $5 million, $5 million, and $3 million, respectively, for the year ended December 31, 2021 and $9 million, $3 million, $4 million, and $2 million, respectively, for the year ended December 31, 2020.

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)]	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
As of December 31, 2021								
Operating lease ROU assets								
Other deferred debits and other assets	$ 875	$ 5	$ 1	$ 16	$ 209	$ 43	$ 46	$ 11
Operating lease liabilities								
Other current liabilities	124	2	—	15	31	6	8	3
Other deferred credits and other liabilities	968	3	1	4	195	40	49	9
Total operating lease liabilities	$ 1,092	$ 5	$ 1	$ 19	$ 226	$ 46	$ 57	$ 12
As of December 31, 2020								
Operating lease ROU assets								
Other deferred debits and other assets	$ 1,064	$ 7	$ 1	$ 46	$ 241	$ 49	$ 54	$ 15
Operating lease liabilities								
Other current liabilities	213	3	—	45	31	6	9	4
Other deferred credits and other liabilities	1,089	5	1	19	224	46	56	11
Total operating lease liabilities	$ 1,302	$ 8	$ 1	$ 64	$ 255	$ 52	$ 65	$ 15

(a) Exelon's operating ROU assets and lease liabilities include $293 million and $429 million, respectively, related to contracted generation as of December 31, 2021, and $387 million and $528 million, respectively, as of December 31, 2020.

	Finance Leases			
	PHI	Pepco	DPL	ACE
As of December 31, 2021				
Finance lease ROU assets				
Plant, property and equipment, net	$ 73	$ 25	$ 29	$ 19
Finance lease liabilities				
Long-term debt due within one year	10	3	4	3
Long-term debt	64	23	25	16
Total finance lease liabilities	$ 74	$ 26	$ 29	$ 19
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	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
As of December 31, 2021	9.8	3.3	6.1	13.7	7.5	8.6	8.5	3.5
As of December 31, 2020	10.1	3.8	4.2	8.3	8.2	9.1	9.1	4.0
As of December 31, 2019	10.1	4.6	4.4	5.4	9.0	9.8	9.7	4.7

	Finance Leases			
	PHI	Pepco	DPL	ACE
As of December 31, 2021	6.1	5.9	6.1	6.3
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	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
As of December 31, 2021	4.7 %	2.8 %	2.2 %	4.0 %	4.2 %	4.0 %	4.0 %	3.4 %
As of December 31, 2020	4.7 %	3.0 %	2.9 %	3.8 %	4.2 %	4.0 %	4.0 %	3.5 %
As of December 31, 2019	4.6 %	3.0 %	3.2 %	3.6 %	4.2 %	4.0 %	4.0 %	3.6 %

	Finance Leases			
	PHI	Pepco	DPL	ACE
As of December 31, 2021	2.2 %	2.3 %	2.1 %	2.1 %
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, 2021 were as follows:

	Operating Leases							
Year	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2022	$ 156	$ 2	$ —	$ 16	$ 38	$ 8	$ 10	$ 4
2023	144	1	—	1	37	7	10	3
2024	140	1	—	—	36	7	8	3
2025	140	1	—	—	34	6	7	2
2026	135	—	—	—	29	5	5	1
Remaining years	693	—	1	18	94	22	30	—
Total	1,408	5	1	35	268	55	70	13
Interest	316	—	—	16	42	9	13	1
Total operating lease liabilities	$ 1,092	$ 5	$ 1	$ 19	$ 226	$ 46	$ 57	$ 12

	Finance Leases			
Year	**PHI**	**Pepco**	**DPL**	**ACE**
2022	$ 12	$ 4	$ 5	$ 3
2023	12	4	5	3
2024	13	5	5	3
2025	12	4	5	3
2026	12	4	5	3
Remaining years	18	6	7	5
Total	79	27	32	20
Interest	5	1	3	1
Total finance lease liabilities	$ 74	$ 26	$ 29	$ 19

Cash paid for amounts included in the measurement of operating and finance lease liabilities were as follows:

	Operating cash flows from operating leases							
	Exelon	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
For the year ended December 31, 2021	$ 255	$ 3	$ —	$ 46	$ 39	$ 8	$ 9	$ 4
For the year ended December 31, 2020	271	3	1	20	39	8	9	4
For the year ended December 31, 2019	287	3	—	33	37	9	6	5

	Financing cash flows from finance leases			
	PHI	**Pepco**	**DPL**	**ACE**
For the year ended December 31, 2021	$ 10	$ 3	$ 4	$ 3
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	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
For the year ended December 31, 2021	$ (1)	$ —	$ —	$ (1)	$ 1	$ —	$ 1	$ —
For the year ended December 31, 2020	1	—	1	—	(1)	—	(1)	—
For the year ended December 31, 2019	52	6	—	2	(3)	(1)	(2)	(1)

	Finance Leases			
	PHI	**Pepco**	**DPL**	**ACE**
For the year ended December 31, 2021	$ 32	$ 12	$ 12	$ 8
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, 2021.

	Exelon	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Contracted generation	●							
Real estate	●	●	●	●	●	●	●	

(in years)	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Remaining lease terms	1-81	1-15	1-81	21	1-11	1-4	10-11	N/A
Options to extend the term	1-79	5-79	5-50	N/A	5	N/A	N/A	N/A

The components of lease income were as follows:

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the year ended December 31, 2021								
Operating lease income	$ 52	$ —	$ —	$ —	$ 4	$ —	$ 3	$ —
Variable lease income	262	—	—	—	1	—	1	—
For the year ended December 31, 2020								
Operating lease income	$ 52	$ —	$ —	$ —	$ 3	$ —	$ 3	$ —
Variable lease income	283	—	—	—	1	—	1	—
For the year ended December 31, 2019								
Operating lease income	$ 54	$ —	$ —	$ —	$ 5	$ —	$ 4	$ —
Variable lease income	261	—	—	—	3	—	3	—

Future minimum lease payments to be recovered under operating leases as of December 31, 2021 were as follows:

Year	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2022	$ 50	$ —	$ —	$ —	$ 4	$ —	$ 3	$ —
2023	49	—	—	—	3	—	3	—
2024	49	—	—	—	4	—	4	—
2025	49	—	—	—	4	—	4	—
2026	49	—	—	—	4	—	4	—
Remaining years	169	1	4	1	26	—	26	—
Total	$ 415	$ 1	$ 4	$ 1	$ 45	$ —	$ 44	$ —

12. Asset Impairments (Exelon)

Exelon 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. Exelon determines if long-lived assets or asset groups are potentially impaired by comparing the undiscounted expected future cash flows to the carrying value when indicators of impairment exist. When the undiscounted cash flow analysis indicates a long-lived asset or asset group may not be recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset 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 Exelon's long-lived assets.

New England Asset Group

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 in Operating and maintenance expense in Exelon’s Consolidated Statement of Operations and Comprehensive Income. See Note 7 - Early Plant Retirements for additional information.

In the second quarter of 2021, an overall decline in the asset group's portfolio value suggested that the carrying value of the New England asset group may be impaired. Generation completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group and concluded that the carrying value was not recoverable and that its fair value was less than its carrying value. As a result, a pre-tax impairment charge of $350 million was recorded in the second quarter of 2021 in Operating and maintenance expense in Exelon’s Consolidated Statement of Operations and Comprehensive Income.

Contracted Wind Project

In the third quarter of 2021, significant long-term operational issues anticipated for a specific wind turbine technology suggested that the carrying value of a contracted wind asset, located in Maryland and part of the CRP joint venture, may be impaired. Generation completed a comprehensive review of the estimated undiscounted future cash flows and concluded that the carrying value of this contracted wind project was not recoverable and that its fair value was less than its carrying value. As a result, in the third quarter of 2021, a pre-tax impairment charge of $45 million was recorded in Operating and maintenance expense, $21 million of which was offset in Net income attributable to noncontrolling interests in Exelon’s Consolidated Statement of Operations and Comprehensive Income.

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 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 the Consolidated Statement of Operations and Comprehensive Income. As a result, Generation accelerated the amortization of investment tax credits associated with these companies and Exelon 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 earnings. See Note 23 — Variable Interest Entities for additional information.

13. Intangible Assets

Goodwill (Exelon, ComEd, PHI, Pepco, DPL, and ACE)

The following table presents the gross amount, accumulated impairment loss, and carrying amount of goodwill at Exelon, ComEd, and PHI as of December 31, 2021 and 2020. There were no additions or impairments during the years ended December 31, 2021 and 2020.

	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.

2021 and 2020 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, 2021 and 2020. 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 and PHI)

Exelon’s other intangible assets, included in Other current assets and Other deferred debits and other assets in the Consolidated Balance Sheets, consisted of the following as of December 31, 2021 and 2020. Exelon's and PHI's other intangible liabilities, included in current and noncurrent Unamortized energy contract liabilities in their Consolidated Balance Sheets, consisted of the following as of December 31, 2021 and 2020. 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, 2021			December 31, 2020		
	Gross	Accumulated Amortization	Net	Gross	Accumulated Amortization	Net
Exelon						
Unamortized Energy Contracts	$ 448	$ (393)	$ 55	$ 448	$ (454)	$ (6)
Customer Relationships	330	(243)	87	326	(215)	111
Trade Name	222	(218)	4	222	(197)	25
Software License	95	(62)	33	95	(53)	42
Exelon Total	$ 1,095	$ (916)	$ 179	$ 1,091	$ (919)	$ 172
PHI						
Unamortized Energy Contracts	$ (1,515)	$ 1,280	$ (235)	$ (1,515)	$ 1,188	$ (327)

The following table summarizes the amortization expense related to intangible assets and liabilities for each of the years ended December 31, 2021, 2020, and 2019:

For the Years Ended December 31,	Exelon[(a)(b)]	PHI[(b)]
2021	$ (3)	$ (92)
2020	(17)	(115)
2019	(28)	(119)

(a) See Note 24 - Supplemental Financial Information for additional information related to the amortization of unamortized energy contracts.

(b) For PHI unamortized energy contracts, the amortization of the fair value adjustment amounts and the corresponding offsetting regulatory asset amounts are amortized through Purchased power and fuel expense in their Consolidated Statements of Operations and Comprehensive Income resulting in no effect to net income.

The following table summarizes the estimated future amortization expense related to intangible assets and liabilities as of December 31, 2021:

For the Years Ending December 31,	Exelon	PHI
2022	$ (19)	$ (89)
2023	(18)	(81)
2024	22	(38)
2025	43	(5)
2026	32	(5)

Renewable Energy Credits (Exelon)

RECs are included in Renewable energy credits in Exelon's 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 current RECs as of December 31, 2021 and 2020:

	As of December 31, 2021	As of December 31, 2020
Current REC's	$ 529	$ 632

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, 2021							
	Exelon	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Included in operations:								
Federal								
Current	$ 322	$ (30)	$ 1	$ (18)	$ 18	$ 22	$ 2	$ 1
Deferred	(66)	113	20	34	(52)	(17)	(14)	(26)
Investment tax credit amortization	(18)	(1)	—	—	(1)	—	—	—
State								
Current	32	(41)	—	—	—	1	1	—
Deferred	100	131	(9)	(51)	77	9	53	12
Total	$ 370	$ 172	$ 12	$ (35)	$ 42	$ 15	$ 42	$ (13)

	For the Year Ended December 31, 2020							
	Exelon	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Included in operations:								
Federal								
Current	$ 26	$ (24)	$ (7)	$ 4	$ 25	$ 40	$ (13)	$ (4)
Deferred	156	112	1	10	(129)	(62)	(20)	(43)
Investment tax credit amortization	(28)	(2)	—	—	(1)	—	—	—
State								
Current	42	(27)	—	—	(5)	—	—	—
Deferred	177	118	(24)	27	33	15	8	6
Total	$ 373	$ 177	$ (30)	$ 41	$ (77)	$ (7)	$ (25)	$ (41)

	For the Year Ended December 31, 2019							
	Exelon	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Included in operations:								
Federal								
Current	$ 85	$ 59	$ 45	$ (51)	$ 43	$ 16	$ 29	$ (3)
Deferred	489	15	20	95	(34)	(6)	(21)	(6)
Investment tax credit amortization	(72)	(2)	—	—	(1)	—	—	—
State								
Current	5	(5)	—	—	3	—	—	—
Deferred	267	96	—	35	27	6	14	9
Total	$ 774	$ 163	$ 65	$ 79	$ 38	$ 16	$ 22	$ —

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, 2021[a]							
	Exelon	**ComEd**	**PECO[b]**	**BGE[b]**	**PHI**	**Pepco**	**DPL[b]**	**ACE[b]**
U.S. federal statutory rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State income taxes, net of federal income tax benefit	4.8	7.8	(1.4)	(10.8)	10.1	2.7	25.0	7.4
Qualified NDT fund income	11.3	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis differences	(0.7)	(0.1)	—	(0.1)	(0.1)	—	(0.2)	(0.2)
Plant basis differences	(4.1)	(0.8)	(13.6)	(1.7)	(1.1)	(1.6)	(0.8)	(0.2)
Production tax credits and other credits	(2.5)	(0.5)	—	(0.9)	(0.5)	(0.5)	(0.4)	(0.5)
Excess deferred tax amortization	(12.9)	(7.6)	(3.8)	(16.3)	(22.4)	(16.4)	(20.0)	(37.1)
Other	(0.1)	(1.0)	0.1	(0.6)	—	(0.4)	0.1	(0.2)
Effective income tax rate	16.8 %	18.8 %	2.3 %	(9.4)%	7.0 %	4.8 %	24.7 %	(9.8)%

	For the Year Ended December 31, 2020[a]							
	Exelon	**ComEd[c]**	**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 %
Increase (decrease) due to:								
State income taxes, net of federal income tax benefit	7.8	11.6	(4.5)	5.5	5.1	4.5	6.6	7.0
Qualified NDT fund income	8.4	—	—	—	—	—	—	—
Deferred Prosecution Agreement payments	1.8	6.8	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis differences	(1.1)	(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)	(0.3)	—	(0.4)	(0.3)	(0.3)	(0.3)	(0.5)
Noncontrolling interests	1.1	—	—	—	—	—	—	—
Excess deferred tax amortization	(13.6)	(11.2)	(4.6)	(13.9)	(42.0)	(25.4)	(51.7)	(82.1)
Tax Settlements[e]	(3.7)	—	—	—	—	—	—	—
Other	0.5	1.8	(0.4)	(0.1)	(0.4)	(0.7)	0.1	0.4
Effective income tax rate	16.0 %	28.8 %	(7.2)%	10.5 %	(18.4)%	(2.7)%	(25.0)%	(57.7)%

	For the Year Ended December 31, 2019[a]							
	Exelon	**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 %
Increase (decrease) due to:								
State income taxes, net of federal income tax benefit	5.4	8.5	—	6.4	4.7	2.0	6.8	7.0
Qualified NDT fund income	5.9	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis differences	(1.5)	(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)	(1.2)	—	(1.3)	(0.2)	(0.1)	—	(0.1)
Noncontrolling interests	(0.6)	—	—	—	—	—	—	—
Excess deferred tax amortization	(5.5)	(9.7)	(2.8)	(6.8)	(17.5)	(15.1)	(14.2)	(27.0)
Other	(0.8)	0.8	—	—	0.8	0.3	—	0.1
Effective income tax rate	19.4 %	19.2 %	11.0 %	18.0 %	7.4 %	6.2 %	13.0 %	— %

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

(b) For PECO, the lower effective tax rate is primarily related to plant basis differences attributable to tax repair deductions. For BGE, the income tax benefit is primarily due to the Maryland multi-year plan which resulted in the acceleration of certain income tax benefits. For DPL, the higher effective tax rate is primarily related to a state income tax expense, net of federal income tax benefit, due to the recognition of a valuation allowance of approximately $31 million against a deferred tax asset associated with Delaware net operating loss carryforwards as a result of a change in Delaware tax law. For ACE, the income tax benefit is primarily due to a distribution rate case settlement which allows ACE to retain certain tax benefits.

(c) At ComEd, the higher effective tax rate is primarily related to the nondeductible Deferred Prosecution Agreement payments. 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 in 2021.

(d) For BGE, PHI, Pepco, DPL, and ACE, the income tax benefit is primarily attributable to accelerated amortization of transmission related deferred income tax regulatory liabilities as a result of regulatory settlements. See Note 3 — Regulatory Matters for additional information.

(e) Exelon'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 benefits resulted in an increase to Exelon’s net income of $76 million for the first quarter of 2020, reflecting a decrease to Exelon’s income tax expense of $67 million.

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, 2021 and 2020 are presented below:

	As of December 31, 2021							
	Exelon	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Plant basis differences	$ (14,429)	$ (4,648)	$(2,271)	$ (1,826)	$ (2,976)	$(1,321)	$ (853)	$ (777)
Accrual based contracts	18	—	—	—	56	—	—	—
Derivatives and other financial instruments	(109)	61	—	—	2	—	—	—
Deferred pension and postretirement obligation	1,054	(308)	(32)	(37)	(90)	(76)	(40)	(6)
Nuclear decommissioning activities	(912)	—	—	—	—	—	—	—
Deferred debt refinancing costs	161	(6)	—	(2)	123	(2)	(1)	(1)
Regulatory assets and liabilities	(1,130)	8	(280)	92	(53)	24	55	31
Tax loss carryforward, net of valuation allowances	295	—	65	68	64	2	18	42
Tax credit carryforward	778	—	—	—	—	—	—	—
Investment in partnerships	(273)	—	—	—	—	—	—	—
Other, net	789	216	97	21	212	99	19	34
Deferred income tax liabilities (net)	$ (13,758)	$ (4,677)	$(2,421)	$ (1,684)	$ (2,662)	$(1,274)	$ (802)	$ (677)
Unamortized investment tax credits	(384)	(8)	—	(2)	(5)	(1)	(1)	(2)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$ (14,142)	$ (4,685)	$(2,421)	$ (1,686)	$ (2,667)	$(1,275)	$ (803)	$ (679)

	As of December 31, 2020							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Plant basis differences	$ (13,868)	$ (4,432)	$(2,131)	$(1,711)	$ (2,822)	$(1,259)	$ (806)	$ (725)
Accrual based contracts	40	—	—	—	77	—	—	—
Derivatives and other financial instruments	41	84	—	—	2	—	—	—
Deferred pension and postretirement obligation	1,559	(288)	(30)	(33)	(80)	(74)	(40)	(7)
Nuclear decommissioning activities	(742)	—	—	—	—	—	—	—
Deferred debt refinancing costs	169	(6)	—	(2)	131	(3)	(1)	(1)
Regulatory assets and liabilities	(1,107)	87	(231)	142	(41)	38	67	46
Tax loss carryforward, net of valuation allowances	286	—	47	57	90	4	49	38
Tax credit carryforward	841	—	—	—	—	—	—	—
Investment in partnerships	(835)	—	—	—	—	—	—	—
Other, net	1,070	223	104	29	220	107	18	27
Deferred income tax liabilities (net)	$ (12,546)	$ (4,332)	$(2,241)	$(1,518)	$ (2,423)	$(1,187)	$ (713)	$ (622)
Unamortized investment tax credits[a]	(464)	(9)	(1)	(3)	(6)	(2)	(2)	(3)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$ (13,010)	$ (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.

The following table provides Exelon's, PECO's, BGE's, PHI's, Pepco's, DPL's, and ACE's carryforwards, of which the state related items are presented on a post-apportioned basis, and any corresponding valuation allowances as of December 31, 2021. ComEd does not have net operating losses or credit carryforwards for the year ended December 31, 2021.

	Exelon	PECO	BGE	PHI	Pepco	DPL	ACE
Federal							
Federal general business credits carryforwards and other carryforwards[a]	$ 806	$ —	$ —	$ —	$ —	$ —	$ —
State							
State net operating losses and other carryforwards	5,485	890	1,098	1,512	42	736	605
Deferred taxes on state tax attributes (net of federal taxes)	365	70	72	104	3	50	43
Valuation allowance on state tax attributes (net of federal taxes)[b]	59	3	—	31	—	31	—
Year in which net operating loss or credit carryforwards will begin to expire[c]	2035	2032	2033	2029	N/A	2032	2031

(a) For Exelon, the federal general business credit carryforward will begin expiring in 2035.

(b) At Exelon, a full valuation allowance has been recorded against certain separate company state net operating loss carryforwards that are expected to expire before realization. At PECO, a full valuation allowance has been recorded against Pennsylvania charitable contributions carryforwards that are expected to expire before realization. At DPL, a full valuation allowance has been recorded against Delaware net operating losses carryforwards due to a change in Delaware tax law.

(c) A portion of Exelon's, BGE's, Pepco's, and DPL's Maryland state net operating loss carryforward have an indefinite carryforward period.

Tabular Reconciliation of Unrecognized Tax Benefits

The following table presents changes in unrecognized tax benefits, for Exelon, PHI, and ACE. ComEd's, PECO's, BGE's, Pepco's, and DPL's amounts are not material.

	Exelon	PHI	ACE
Balance at January 1, 2019	$ 477	$ 45	$ 14
Change to positions that only affect timing	26	3	—
Increases based on tax positions related to 2019	2	—	—
Increases based on tax positions prior to 2019	34	—	—
Decreases based on tax positions prior to 2019	(3)	—	—
Decrease from settlements with taxing authorities	(29)	—	—
Balance at December 31, 2019	507	48	14
Change to positions that only affect timing	6	3	1
Increases based on tax positions related to 2020	3	—	—
Increases based on tax positions prior to 2020	26	1	—
Decreases based on tax positions prior to 2020[a]	(348)	—	—
Decrease from settlements with taxing authorities[a]	(69)	—	—
Balance at December 31, 2020	125	52	15
Change to positions that only affect timing	13	3	1
Increases based on tax positions related to 2021	4	1	—
Increases based on tax positions prior to 2021	4	—	—
Decreases based on tax positions prior to 2021	(3)	—	—
Decrease from settlements with taxing authorities	—	—	—
Balance at December 31, 2021	$ 143	$ 56	$ 16

(a) Exelon'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 net income of $76 million in the first quarter of 2020, reflecting a decrease to Exelon's income tax expense of $67 million.

Recognition of unrecognized tax benefits

The following table presents Exelon's unrecognized tax benefits that, if recognized, would decrease the effective tax rate. The Utility Registrants' amounts are not material.

	Exelon
December 31, 2021	$ 77
December 31, 2020	73
December 31, 2019	462

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, 2021, ACE has approximately $14 million of unrecognized state tax benefits that could significantly decrease within the 12 months after the reporting date based on the outcome of pending court cases involving other taxpayers. The unrecognized tax benefit, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

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. The Utility Registrants' amounts are not material.

Net interest and penalties receivable as of	Exelon
December 31, 2021[a]	$ 43
December 31, 2020	314

(a) As of December 31, 2021, the interest receivable balance is not expected to be settled in cash within the next twelve months and therefore classified as non-current receivable. In December of 2021, Exelon received a refund of approximately $272 million related to an interest netting refund claim.

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]	2010-2020	All Registrants
Delaware separate corporate income tax returns	Same as federal	DPL
District of Columbia combined corporate income tax returns	2018-2020	Exelon, PHI, Pepco
Illinois unitary corporate income tax returns	2012-2020	Exelon, ComEd
Maryland separate company corporate net income tax returns	Same as federal	BGE, Pepco, DPL
New Jersey separate corporate income tax returns	2017-2018	Exelon
New Jersey combined corporate income tax returns	2019-2020	Exelon
New Jersey separate corporate income tax returns	2017-2020	ACE
New York combined corporate income tax returns	2011-2020	Exelon
Pennsylvania separate corporate income tax returns	2011-2016	Exelon
Pennsylvania separate corporate income tax returns	2018-2020	Exelon
Pennsylvania separate corporate income tax returns	2018-2020	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

CENG Put Option (Exelon)

On August 6, 2021, Generation entered into a settlement agreement pursuant to which Generation purchased EDF's equity interest in CENG. Exelon recorded deferred tax liabilities of $290 million against Common Stock in Exelon's Consolidated Balance Sheet. The deferred tax liabilities represent the tax effect on the difference between the net purchase price and EDF's noncontrolling interest as of August 6, 2021. The deferred tax liabilities will reverse during the remaining operating lives and during decommissioning of the CENG nuclear plants. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

Long-Term Marginal State Income Tax Rate (All Registrants)

Quarterly, Exelon reviews and updates its marginal state income tax rates and updates for material changes in state tax laws and 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, 2021, 2020, and 2019 were not material.

December 31, 2021	Exelon
Increase to Deferred Income Tax Liability and Income Tax Expense, Net of Federal Taxes	$ 27
December 31, 2020	
Increase to Deferred Income Tax Liability and Income Tax Expense, Net of Federal Taxes	$ 66
December 31, 2019	
Increase to Deferred Income Tax Liability and Income Tax Expense, Net of Federal Taxes	$ 20

Allocation of Tax Benefits (All Registrants)

The Utility Registrants are 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 are reallocated to the other Registrants. That allocation is treated as a contribution from Exelon to the party receiving the benefit.

The following table presents the allocation of tax benefits from Exelon under the Tax Sharing Agreement.

	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2021[a]	$ 1	$ 19	$ —	$ 17	$ 16	$ —	$ —
December 31, 2020[b]	14	17	—	17	8	6	1
December 31, 2019[c]	—	14	3	7	6	1	—

(a) BGE, 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.

(b) 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.

(c) ComEd 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 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 net income of $108 million for the year ended December 31, 2019, reflecting a decrease to Exelon’s Income tax expense of $97 million.

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, January 1, 2021 for most newly-hired utility management employees, and for certain newly-hired union employees pursuant to their collective bargaining agreements, 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, 2022, management employees retiring on or after that date are no longer eligible for retiree life insurance 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.

Effective February 1, 2022, in connection with the separation, pension and OPEB obligations and assets for current and former Generation employees and shared service employees supporting Generation, were transferred to pension and OPEB plans and trusts established by Generation.

The tables below show the pension and OPEB plans in which employees of each operating company participated as of December 31, 2021:

	Operating Company[(e)]							
Name of Plan:	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**	**Generation**
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	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:	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**	**Generation**
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	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		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 2021, Exelon received an updated valuation of its pension and OPEB to reflect actual census data as of January 1, 2021. This valuation resulted in an increase to the pension obligations of $33 million and a decrease to the OPEB obligations of $9 million. Additionally, accumulated other comprehensive loss increased by $1 million (after-tax) and regulatory assets and liabilities increased by $21 million and $1 million, respectively.

The 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	
	2021	2020	2021	2020
Change in benefit obligation:				
Net benefit obligation as of the beginning of year	$ 24,894	$ 22,868	$ 4,604	$ 4,658
Service cost	439	387	80	90
Interest cost	641	757	114	154
Plan participants' contributions	—	—	50	49
Actuarial (gain) loss[a]	(630)	2,217	(223)	49
Plan amendments	—	—	—	(111)
Settlements	(88)	(45)	(5)	(5)
Gross benefits paid	(1,410)	(1,290)	(292)	(280)
Net benefit obligation as of the end of year	$ 23,846	$ 24,894	$ 4,328	$ 4,604

	Pension Benefits		OPEB	
	2021	2020	2021	2020
Change in plan assets:				
Fair value of net plan assets as of the beginning of year	$ 20,344	$ 18,590	$ 2,554	$ 2,541
Actual return on plan assets	1,407	2,547	203	190
Employer contributions	574	542	91	59
Plan participants' contributions	—	—	50	49
Gross benefits paid	(1,410)	(1,290)	(292)	(280)
Settlements	(88)	(45)	(5)	(5)
Fair value of net plan assets as of the end of year	$ 20,827	$ 20,344	$ 2,601	$ 2,554

(a) The pension and OPEB gains in 2021 primarily reflect an increase in the discount rate. In 2020, the actuarial losses 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	
	2021	2020	2021	2020
Other current liabilities	$ 29	$ 47	$ 42	$ 42
Pension obligations	2,990	4,503	—	—
Non-pension postretirement benefit obligations	—	—	1,685	2,008
Unfunded status (net benefit obligation less plan assets)	$ 3,019	$ 4,550	$ 1,727	$ 2,050

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.

	Exelon	
ABO in Excess of Plan Assets	**2021**	**2020**
ABO	$ 22,609	$ 23,514
Fair value of net plan assets	20,827	20,344

Components of Net Periodic Benefit Costs

The majority of the 2021 pension benefit cost for the Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 2.58%. The majority of the 2021 OPEB cost is calculated using an expected long-term rate of return on plan assets of 6.46% for funded plans and a discount rate of 2.51%.

A portion of the net periodic benefit cost for all plans is capitalized in 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, 2021, 2020, and 2019.

	Pension Benefits			OPEB		
	2021	**2020**	**2019**	**2021**	**2020**	**2019**
Components of net periodic benefit cost:						
Service cost	$ 439	$ 387	$ 357	$ 80	$ 90	$ 93
Interest cost	641	757	883	114	154	188
Expected return on assets	(1,336)	(1,270)	(1,225)	(158)	(163)	(153)
Amortization of:						
Prior service cost (credit)	3	4	—	(34)	(124)	(179)
Actuarial loss	598	512	414	37	49	45
Curtailment benefits	—	—	—	—	(1)	—
Settlement and other charges	27	14	17	1	1	1
Contractual termination benefits	—	—	1	—	—	—
Net periodic benefit cost	$ 372	$ 404	$ 447	$ 40	$ 6	$ (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 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	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2021	$ 411	$ 129	$ 8	$ 64	$ 49	$ 6	$ 2	$ 11
2020	411	114	5	64	70	15	7	14
2019	442	96	12	61	95	25	15	16

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 in 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, 2021, 2020, and 2019 for all plans combined.

	Pension Benefits			OPEB		
	2021	2020	2019	2021	2020	2019
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets (liabilities):						
Current year actuarial (gain) loss	$ (700)	$ 941	$ 538	$ (270)	$ 22	$ 80
Amortization of actuarial loss	(598)	(512)	(414)	(37)	(49)	(45)
Current year prior service cost (credit)	—	—	68	—	(111)	—
Amortization of prior service (cost) credit	(3)	(4)	—	34	124	179
Curtailments	—	—	(3)	—	1	—
Settlements	(27)	(14)	(17)	(1)	(1)	(1)
Total recognized in AOCI and regulatory assets (liabilities)	$ (1,328)	$ 411	$ 172	$ (274)	$ (14)	$ 213
Total recognized in AOCI	$ (747)	$ 271	$ 169	$ (130)	$ 6	$ 107
Total recognized in regulatory assets (liabilities)	$ (581)	$ 140	$ 3	$ (144)	$ (20)	$ 106

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 as of December 31, 2021 and 2020, respectively, for all plans combined:

	Pension Benefits		OPEB	
	2021	2020	2021	2020
Prior service cost (credit)	$ 32	$ 35	$ (111)	$ (145)
Actuarial loss	6,752	8,077	230	538
Total	$ 6,784	$ 8,112	$ 119	$ 393
Total included in AOCI	$ 3,592	$ 4,339	$ 53	$ 183
Total included in regulatory assets (liabilities)	$ 3,192	$ 3,773	$ 66	$ 210

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:

	2021	2020	2019
Pension plans	12.4	12.3	11.7
OPEB plans:			
Benefit Eligibility Age	7.6	9.0	8.7
Expected Retirement	8.8	10.2	9.3

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, 2021, Exelon's mortality assumption utilizes the SOA 2019 base table (Pri-2012) and MP-2021 improvement scale adjusted to use Proxy SSA ultimate improvement rates._ 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 Exelon, the following assumptions were used to determine the benefit obligations for the plans as of December 31, 2021 and 2020. 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	
	2021	2020	2021	2020
Discount rate	2.92 % [(a)]	2.58 % [(a)]	2.88 % [(a)]	2.51 % [(a)]
Investment crediting rate	3.75 % [(b)]	3.72 % [(b)]	N/A	N/A
Rate of compensation increase	3.75 %	3.75 %	3.75 %	3.75 %
Mortality table	Pri-2012 table with MP- 2021 improvement scale (adjusted)	Pri-2012 table with MP- 2020 improvement scale (adjusted)	Pri-2012 table with MP- 2021 improvement scale (adjusted)	Pri-2012 table with MP- 2020 improvement scale (adjusted)
Health care cost trend on covered charges	N/A	N/A	Initial and ultimate rate of 5.00%	Initial and ultimate trend of 5.00%

(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 2.55% - 3.02% and 2.84% - 2.92% for pension and OPEB plans, respectively, as of December 31, 2021 and 2.11% - 2.73% and 2.45% - 2.63% for pension and OPEB plans, respectively, as of December 31, 2020.

(b) The investment crediting rate above represents a weighted average rate.

The following assumptions were used to determine the net periodic benefit cost for Exelon for the years ended December 31, 2021, 2020 and 2019:

	Pension Benefits			OPEB		
	2021	2020	2019	2021	2020	2019
Discount rate	2.58 % [(a)]	3.34 % [(a)]	4.31 % [(a)]	2.51 % [(a)]	3.31 % [(a)]	4.30 % [(a)]
Investment crediting rate	3.72 % [(b)]	3.82 % [(b)]	4.46 % [(b)]	N/A	N/A	N/A
Expected return on plan assets	7.00 % [(c)]	7.00 % [(c)]	7.00 % [(c)]	6.46 % [(c)]	6.69 % [(c)]	6.67 % [(c)]
Rate of compensation increase	3.75 % [(d)]	3.75 % [(d)]	3.25 % [(d)]	3.75 % [(d)]	3.75 % [(d)]	3.25 % [(d)]
Mortality table	Pri-2012 table with MP- 2020 improvement scale (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)	Pri-2012 table with MP- 2020 improvement scale (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)
Health care cost trend on covered charges	N/A	N/A	N/A	Initial and ultimate rate of 5.00%	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 establish the majority of Exelon's pension and OPEB costs. Certain benefit plans used individual rates, which range from 2.11%-2.73% and 2.45%-2.63% for pension and OPEB plans, respectively, for the year ended December 31, 2021; 3.02%-3.44% and 3.27%-3.40% for pension and OPEB plans; respectively, for the year ended December 31, 2020; and 4.13%-4.36% and 4.27%-4.38% for pension and OPEB plans, respectively, for the year ended December 31, 2019.

(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		
	2021	2020	2019	2021	2020	2019
Exelon	$ 574	$ 542	$ 356	$ 91	$ 59	$ 51
ComEd	174	143	72	22	5	5
PECO	17	18	27	1	—	1
BGE	57	56	34	24	22	14
PHI	39	30	10	9	9	15
Pepco	2	2	2	9	9	12
DPL	1	—	1	—	—	—
ACE	3	2	—	—	—	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 2022. Exelon's estimated contributions include contributions related to Generation's qualified pension plans. In connection with the separation, an additional qualified pension contribution of $207 million was completed on February 1, 2022. 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 2022:

	Qualified Pension Plans	Non-Qualified Pension Plans	OPEB
Exelon	$ 505	$ 32	$ 50
ComEd	173	2	12
PECO	12	1	2
BGE	48	2	16
PHI	60	10	7
Pepco	2	1	6
DPL	1	1	—
ACE	7	—	—

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans as of December 31, 2021 were:

	Pension Benefits	OPEB
2022	$ 1,288	$ 253
2023	1,298	254
2024	1,326	255
2025	1,330	255
2026	1,326	258
2027 through 2031	6,736	1,284
Total estimated future benefits payments through 2031	$ 13,304	$ 2,559

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, 2021 were 7.21% and 9.54%, respectively, compared to an expected long-term return assumption of 7.00% and 6.46%, respectively. Exelon used an EROA of 7.00% and 6.44% to estimate its 2022 pension and OPEB costs, respectively.

Exelon's pension and OPEB plan target asset allocations as of December 31, 2021 and 2020 were as follows:

	December 31, 2021		December 31, 2020	
Asset Category	**Pension Benefits**	**OPEB**	**Pension Benefits**	**OPEB**
Equity securities	35 %	44 %	34 %	45 %
Fixed income securities	41 %	41 %	43 %	39 %
Alternative investments[(a)]	24 %	15 %	23 %	16 %
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, 2021. 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, 2021, 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 as of December 31, 2021 and 2020:

	December 31, 2021					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
Pension plan assets[a]										
Cash equivalents	$ 445	$ 156	$ —	$ —	$ 601	$ 408	$ 121	$ —	$ —	$ 529
Equities[b]	4,621	—	3	2,180	6,804	4,255	—	2	2,552	6,809
Fixed income:										
U.S. Treasury and agencies	1,716	302	—	—	2,018	1,137	367	—	—	1,504
State and municipal debt	—	80	—	—	80	—	85	—	—	85
Corporate debt[c]	—	4,319	557	—	4,876	—	4,873	573	—	5,446
Other[b]	74	276	20	515	885	—	239	21	537	797
Fixed income subtotal	1,790	4,977	577	515	7,859	1,137	5,564	594	537	7,832
Private equity	—	—	—	1,924	1,924	—	—	—	1,632	1,632
Hedge funds	—	—	—	1,325	1,325	—	—	—	1,314	1,314
Real estate	—	—	—	1,301	1,301	—	—	—	1,080	1,080
Private credit	—	—	223	1,033	1,256	—	—	234	1,046	1,280
Pension plan assets subtotal	6,856	5,133	803	8,278	21,070	5,800	5,685	830	8,161	20,476
OPEB plan assets[a]										
Cash equivalents	84	64	—	—	148	50	52	—	—	102
Equities	605	3	—	506	1,114	618	2	—	569	1,189
Fixed income:										
U.S. Treasury and agencies	22	68	—	—	90	16	66	—	—	82
State and municipal debt	—	11	—	—	11	—	89	—	—	89
Corporate debt[c]	—	116	—	—	116	—	89	—	—	89
Other	348	7	—	212	567	285	3	—	179	467
Fixed income subtotal	370	202	—	212	784	301	247	—	179	727
Hedge funds	—	—	—	273	273	—	—	—	308	308
Real estate	—	—	—	134	134	—	—	—	111	111
Private credit	—	—	—	131	131	—	—	—	117	117
OPEB plan assets subtotal	1,059	269	—	1,256	2,584	969	301	—	1,284	2,554
Total pension and OPEB plan assets[d]	$ 7,915	$ 5,402	$ 803	$ 9,534	$ 23,654	$ 6,769	$ 5,986	$ 830	$ 9,445	$ 23,030

(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 $(3) million and $2 million for the years ended December 31, 2021 and 2020, respectively, which have total notional amounts of $5,959 million and $6,879 million as of December 31, 2021 and 2020, 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 $(75) million and $(96) million as of December 31, 2021 and 2020, respectively. OPEB equities sold short totaled $(28) million and $(42) million as of December 31, 2021 and 2020, respectively.

(d) Excludes net liabilities of $226 million and $132 million as of December 31, 2021 and 2020, respectively, which include certain derivative assets that have notional amounts of $214 million and $239 million as of December 31, 2021 and 2020, 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, interest and dividends receivable, and repurchase agreement obligations. The repurchase agreements generally have maturities ranging from 3-6 months.

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, 2021 and 2020:

	Fixed Income	Equities	Private Credit	Total
Pension Assets				
Balance as of January 1, 2021	$ 594	$ 2	$ 234	$ 830
Actual return on plan assets:				
Relating to assets still held as of the reporting date	(21)	—	31	10
Purchases, sales and settlements:				
Purchases	17	—	9	26
Settlements[a]	(20)	—	(51)	(71)
Transfers into Level 3	7	1	—	8
Balance as of December 31, 2021	$ 577	$ 3	$ 223	$ 803

	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 as of 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

(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 NDT funds. 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, 2021, 2020, and 2019:

For the Years Ended December 31,	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2021	$ 143	$ 35	$ 12	$ 12	14	$ 4	$ 3	$ 2
2020	158	36	12	13	14	4	3	3
2019	161	35	11	12	13	3	3	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. Generation's and ComEd's derivative economic hedges related to commodities, referred to as economic hedges, are recorded at fair value through earnings at Exelon for Generation's economic hedges and for ComEd's economic hedges are offset by a corresponding regulatory asset or liability. For all NPNS derivative instruments, accounts receivable or accounts payable are recorded when derivatives settle and revenue or expense is recognized in earnings as the underlying physical commodity is sold or consumed.

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 is 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	Electricity	NPNS	Fixed price contracts for default supply requirements through full requirements contracts.
	Gas	NPNS	Fixed price contracts to cover about 10% of planned natural gas purchases in support of projected firm sales.
BGE	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
	Gas	NPNS	Fixed price contracts for between 10-20% of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period.
Pepco	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
DPL	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
	Gas	NPNS	Fixed and index priced contracts through full requirements contracts.
		Changes in fair value of economic hedge recorded to an offsetting regulatory asset or liability(b)	Exchange traded future contracts for up to 50% of estimated monthly purchase requirements each month, including purchases for storage injections.
ACE	Electricity	NPNS	Fixed price contracts for all BGS requirements through full requirements contracts.

(a) See Note 3—Regulatory Matters for additional information.

(b) The fair value of the DPL economic hedge is not material as of December 31, 2021 and 2020 and is not presented in the fair value tables below.

The following tables provide a summary of the derivative fair value balances recorded by Exelon and ComEd as of December 31, 2021 and 2020:

	Exelon					ComEd
December 31, 2021	**Economic Hedges**	**Proprietary Trading**	**Collateral[a][b]**	**Netting[a]**	**Total**	**Economic Hedges**
Mark-to-market derivative assets (current assets)	$ 10,915	$ 25	$ 152	$ (8,923)	$ 2,169	$ —
Mark-to-market derivative assets (noncurrent assets)	3,224	2	15	(2,298)	943	—
Total mark-to-market derivative assets	14,139	27	167	(11,221)	3,112	—
Mark-to-market derivative liabilities (current liabilities)	(10,161)	(19)	262	8,923	(995)	(18)
Mark-to-market derivative liabilities (noncurrent liabilities)	(3,094)	(1)	83	2,298	(714)	(201)
Total mark-to-market derivative liabilities	(13,255)	(20)	345	11,221	(1,709)	(219)
Total mark-to-market derivative net assets (liabilities)	$ 884	$ 7	$ 512	$ —	$ 1,403	$ (219)
December 31, 2020						
Mark-to-market derivative assets (current assets)	$ 2,757	$ 40	$ 103	$ (2,261)	$ 639	$ —
Mark-to-market derivative assets (noncurrent assets)	1,501	4	64	(1,015)	554	—
Total mark-to-market derivative assets	4,258	44	167	(3,276)	1,193	—
Mark-to-market derivative liabilities (current liabilities)	(2,662)	(23)	131	2,261	(293)	(33)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,603)	(2)	118	1,015	(472)	(268)
Total mark-to-market derivative liabilities	(4,265)	(25)	249	3,276	(765)	(301)
Total mark-to-market derivative net assets (liabilities)	$ (7)	$ 19	$ 416	$ —	$ 428	$ (301)

(a) Exelon nets 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 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 as of December 31, 2021 and 2020 and not reflected in the table above.

(b) Includes $897 million held and $209 million posted of variation margin with the exchanges as of December 31, 2021 and 2020, respectively.

Economic Hedges (Commodity Price Risk)

Generation. For the years ended December 31, 2021, 2020, and 2019, Exelon 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	**2021**	**2020**	**2019**
Operating revenues	$ (635)	$ 112	$ —
Purchased power and fuel	1,206	168	(204)
Total	$ 571	$ 280	$ (204)

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. For merchant revenues not already hedged via comprehensive state programs, such as the CMC in Illinois, we utilize a three-year ratable sales plan to align our hedging strategy with our financial objectives. The prompt three-year merchant revenues are hedged on an approximate rolling 90%/60%/30% basis. We may also enter into transactions that are outside of this ratable hedging program.

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 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, 2021, 2020, and 2019, net pre-tax commodity mark-to-market gains and losses for Exelon were not material. The Utility Registrants do not execute derivatives for proprietary trading purposes.

Interest Rate and Foreign Exchange Risk (Exelon)

Generation utilizes interest rate swaps to manage its interest rate exposure and foreign currency derivatives to manage foreign exchange rate exposure associated with international commodity purchases in currencies other than U.S. dollars, both of which are treated as economic hedges. The notional amounts were $486 million and $665 million for Exelon as of December 31, 2021 and 2020, respectively.

The mark-to-market derivative assets and liabilities as of December 31, 2021 and 2020 and the mark-to-market gains and losses for the years ended December 31, 2021, 2020, and 2019 were not material for Exelon.

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, 2021. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The amounts in the tables below exclude credit risk exposure from individual retail counterparties, nuclear fuel procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE, NASDAQ, NGX, and Nodal commodity exchanges.

Rating as of December 31, 2021	Total Exposure Before Credit Collateral	Credit Collateral[a]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 715	$ 176	$ 539	1	$ 106
Non-investment grade	13	—	13	—	—
No external ratings					
Internally rated — investment grade	111	—	111	—	—
Internally rated — non-investment grade	226	47	179	—	—
Total	$ 1,065	$ 223	$ 842	1	$ 106

Net Credit Exposure by Type of Counterparty	As of December 31, 2021
Financial institutions	$ 32
Investor-owned utilities, marketers, power producers	711
Energy cooperatives and municipalities	62
Other	37
Total	$ 842

(a) As of December 31, 2021, credit collateral held from counterparties where Generation had credit exposure included $163 million of cash and $60 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, 2021, the amount of cash collateral held with external counterparties by ComEd and DPL was $41 million and $43 million, respectively, which is recorded in Other current liabilities in ComEd's and DPL's Consolidated Balance Sheets. The amounts for PECO, BGE, Pepco, and ACE as of December 31, 2021 and for the Utility Registrants as of December 31, 2020 are 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:

Credit-Risk Related Contingent Features	As of December 31, 2021	As of December 31, 2020
Gross fair value of derivative contracts containing this feature[(a)]	$ (3,872)	$ (834)
Offsetting fair value of in-the-money contracts under master netting arrangements[(b)]	2,424	537
Net fair value of derivative contracts containing this feature[(c)]	$ (1,448)	$ (297)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features ignoring the effects of master netting agreements.

(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which Generation could potentially be required to post collateral.

(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

As of December 31, 2021 and 2020, 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, 2021	As of December 31, 2020
Cash collateral posted	$ 713	$ 511
Letters of credit posted	755	226
Cash collateral held	182	110
Letters of credit held	124	40
Additional collateral required in the event of a credit downgrade below investment grade	2,113	1,432

Generation entered into supply forward contracts with certain utilities, including the Utility Registrants, 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, 2021, PECO, BGE, and DPL were not required to post collateral for any of these agreements. If PECO, BGE, or DPL lost their investment grade credit rating as of December 31, 2021, they could have been required to post incremental collateral to their counterparties of $37 million, $78 million, and $14 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. PECO meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. Pepco, DPL, and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the PHI intercompany money pool. PHI Corporate meets its short-term liquidity requirements primarily through the issuance of short-term notes and borrowings from the Exelon intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

Commercial Paper

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements as of December 31, 2021 and 2020:

	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	**2021[a][b][c]**	**2020[a][b][c]**	**2021**	**2020**	**2021**	**2020**
Exelon[d]	$ 9,000	$ 9,000	$ 1,301	$ 1,031	0.52 %	0.25 %
ComEd	1,000	1,000	—	323	— %	0.23 %
PECO	600	600	—	—	— %	— %
BGE	600	600	130	—	0.37 %	— %
PHI[e]	900	900	469	368	0.35 %	0.24 %
Pepco	300	300	175	35	0.33 %	0.22 %
DPL	300	300	149	146	0.36 %	0.24 %
ACE	300	300	145	187	0.35 %	0.25 %

(a) Excludes $1,200 million and $1,500 million in bilateral credit facilities as of December 31, 2021 and 2020, respectively, and $131 million and $144 million in credit facilities for project finance as of December 31, 2021 and 2020, respectively. These credit facilities do not back the commercial paper program relating to Generation.

(b) As of December 31, 2021, excludes $142 million of credit facility agreements arranged at minority and community banks, including $33 million, $33 million, $8 million, $8 million, $8 million, and $8 million, at ComEd, PECO, BGE, Pepco, DPL, and ACE, respectively. These facilities expire on October 7, 2022. These facilities are solely utilized to issue letters of credit. As of December 31, 2020, excludes $135 million of credit facility agreements arranged primarily at minority and community banks, including $32 million, $33 million, $8 million, $8 million, $8 million, and $8 million, at ComEd, PECO, BGE, Pepco, DPL, and ACE, 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 as of December 31, 2021 and 2020. Exelon Corporate had no outstanding commercial paper as of December 31, 2021 and 2020.

(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.

As of December 31, 2021, the Registrants had the following aggregate bank commitments, credit facility borrowings, and available capacity under their respective credit facilities:

					Available Capacity as of December 31, 2021	
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	$ 10,331	$ —	$ 2,383	$ 7,948	$ 6,461
ComEd	Syndicated Revolver	1,000	—	2	998	998
PECO	Syndicated Revolver	600	—	—	600	600
BGE	Syndicated Revolver	600	—	—	600	470
PHI	Syndicated Revolver	900	—	—	900	431
Pepco	Syndicated Revolver	300	—	—	300	125
DPL	Syndicated Revolver	300	—	—	300	151
ACE	Syndicated Revolver	300	—	—	300	155

(a) On February 1, 2022, Exelon Corporate and the Utility Registrants' respective syndicated revolving credit facilities were replaced with a new 5-year revolving credit facility.

(b) As of December 31, 2021, excludes $142 million of credit facility agreements arranged at minority and community banks, including $33 million, $33 million, $8 million, $8 million, $8 million, and $8 million, at ComEd, PECO, BGE, Pepco, DPL, and ACE, respectively. These facilities expire on October 7, 2022. These facilities are solely utilized to issue letters of credit. As of December 31, 2021, letters of credit issued under these facilities totaled $5 million, $1 million, and $2 million for ComEd, PECO, and BGE, respectively.

(c) Includes $600 million aggregate bank commitment related to Exelon Corporate. Exelon Corporate had $6 million outstanding letters of credit as of December 31, 2021. Exelon Corporate had $594 million in available capacity to support additional commercial paper as of December 31, 2021.

Revolving Credit Agreements

On February 1, 2022, Exelon Corporate and the Utility Registrants each entered into a new 5-year revolving credit facility that replaced its existing syndicated revolving credit facility. The following table reflects the credit agreements:

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

Bilateral Credit Agreements

The following table reflects the bilateral credit agreements as of December 31, 2021:

Subsidiary	Date Initiated	Latest Amendment Date	Maturity Date[a]	Amount
Generation[b][c]	January 11, 2013	March 1, 2021	March 1, 2023	$ 100
Generation[b]	January 5, 2016	April 2, 2021	April 5, 2023	150
Generation[b][c]	February 21, 2019	March 31, 2021	March 31, 2022	100
Generation[b]	October 25, 2019	N/A	N/A	200
Generation[b]	November 20, 2019	N/A	N/A	300
Generation[b]	November 21, 2019	N/A	N/A	150
Generation[b]	November 21, 2019	November 21, 2021	November 21, 2022	100
Generation[b][d]	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 agreements solely support the issuance of letters of credit and do not back the commercial paper program relating to Generation.
(c) The bilateral credit agreement was terminated on January 31, 2022.
(d) On February 9, 2022, the bilateral credit agreement increased to $200 million.

Borrowings under Exelon'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]	ComEd	PECO	BGE	Pepco	DPL	ACE
Prime based borrowings	0 - 27.5	—	—	—	7.5	—	7.5
LIBOR-based borrowings	90.0 - 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 basis points and 127.5 basis points 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.

Short-Term Loan Agreements

On March 23, 2017, Exelon Corporate entered into a term loan agreement for $500 million. The loan agreement was renewed on March 17, 2021 and will expire on March 16, 2022. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.65% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Short-term borrowings in Exelon's Consolidated Balance Sheet.

On March 24, 2021, Exelon Corporate entered into a 9-month term loan agreement for $200 million. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.65% and all indebtedness thereunder is unsecured. Exelon Corporate repaid the term loan on December 22, 2021.

On March 31, 2021, Exelon Corporate entered into a 9-month and 364-day term loan agreement for $150 million each with variable interest rates of LIBOR plus 0.65% and expiration dates of December 31, 2021 and March 30, 2022, respectively. The 364-day loan agreement is reflected in Short-term borrowings in Exelon's Consolidated Balance Sheet. Exelon Corporate repaid the 9-month term loan on December 29, 2021.

In connection with the separation, on January 24, 2022, Exelon Corporate entered into a 364-day term loan agreement for $1.15 billion. The loan agreement will expire on January 23, 2023. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to SOFR plus 0.75% and all indebtedness thereunder is unsecured.

On March 19, 2020, Generation entered into a term loan agreement for $200 million. The loan agreement was renewed on March 17, 2021 and will expire on March 16, 2022. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.875% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Short-term borrowings in Exelon's Consolidated Balance Sheet. In connection with the separation, Generation repaid the term loan on January 26, 2022.

On March 31, 2020, Generation entered into a term loan agreement for $300 million. The loan agreement was renewed on March 30, 2021 and will expire on March 29, 2022. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.70% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Short-term borrowings in Exelon's Consolidated Balance Sheet.

On August 6, 2021, Generation entered into a 364-day term loan agreement for $880 million to fund the purchase of EDF's equity interest in CENG. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate of LIBOR plus 0.875% until March 31, 2022 and a rate of LIBOR plus 1% thereafter and all indebtedness thereunder is unsecured. The loan agreement is reflected in Short-term borrowings in Exelon's Consolidated Balance Sheet. The loan agreement was amended on January 24, 2022 to change the maturity date to June 30, 2022 from August 5, 2022. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

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. ComEd repaid the term loans on March 9, 2021.

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, 2021 and December 31, 2020, $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, 2021 and 2020:

Exelon

	Rates		Maturity Date	December 31,	
				2021	2020
Long-term debt					
First mortgage bonds[(a)(b)(c)]	0.14 % -	7.90 %	2022 - 2051	$ 20,751	$ 18,915
Senior unsecured notes	3.25 % -	7.60 %	2022 - 2050	10,285	10,585
Unsecured notes	2.25 % -	6.35 %	2022 - 2050	4,000	3,700
Notes payable and other	1.64 % -	7.49 %	2022 - 2053	189	170
Junior subordinated notes		3.50 %	2022	1,150	1,150
Long-term software licensing agreement	3.62 % -	3.95 %	2024 - 2025	9	30
Unsecured tax-exempt bonds	0.12 % -	1.70 %	2022 - 2024	143	143
Medium-terms notes (unsecured)		7.72 %	2027	10	10
Transition bonds		5.55 %	2021	—	21
Loan agreement[(d)]		2.00 %	2023	50	50
Nonrecourse debt:					
Fixed rates	2.29 % -	6.00 %	2031 - 2037	909	977
Variable rates	2.98 % -	3.50 %	2026 - 2027	870	765
Total long-term debt				38,366	36,516
Unamortized debt discount and premium, net				(77)	(77)
Unamortized debt issuance costs				(262)	(248)
Fair value adjustment				670	721
Long-term debt due within one year				(3,373)	(1,819)
Long-term debt				$ 35,324	$ 35,093
Long-term debt to financing trusts[(e)]					
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) On November 16, 2021, DPL entered into a purchase agreement of First Mortgage Bonds of $125 million at 3.06% due on February 15, 2052. The closing date of the issuance occurred on February 15, 2022.

(c) On November 16, 2021, ACE entered into a purchase agreement of First Mortgage Bonds of $25 million and $150 million at 2.27% and 3.06% due on February 15, 2032 and February 15, 2052, respectively. The closing date of the issuance occurred on February 15, 2022.

(d) In connection with the separation, Exelon Corporate entered into three 18-month term loan agreements. On January 21, 2022, two of the loan agreements were issued for $300 million each with an expiration date of July 21, 2023. On January 24, 2022, the third loan agreement was issued for $250 million with an expiration date of July 24, 2023. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to SOFR plus 0.65%.

(e) Amounts owed to these financing trusts are recorded as Long-term debt to financing trusts within Exelon’s Consolidated Balance Sheet.

ComEd

	Rates	Maturity Date	December 31, 2021	December 31, 2020
Long-term debt				
First mortgage bonds[a]	2.20 % - 6.45 %	2024 - 2051	$ 9,879	$ 9,079
Other	7.49 %	2053	8	8
Total long-term debt			9,887	9,087
Unamortized debt discount and premium, net			(27)	(28)
Unamortized debt issuance costs			(87)	(76)
Long-term debt due within one year			—	(350)
Long-term debt			$ 9,773	$ 8,633
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 Sheet.

PECO

	Rates	Maturity Date	December 31, 2021	December 31, 2020
Long-term debt				
First mortgage bonds[a]	2.38 % - 5.95 %	2022 - 2051	$ 4,200	$ 3,750
Loan agreement	2.00 %	2023	50	50
Total long-term debt			4,250	3,800
Unamortized debt discount and premium, net			(20)	(20)
Unamortized debt issuance costs			(33)	(27)
Long-term debt due within one year			(350)	(300)
Long-term debt			$ 3,847	$ 3,453
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 Sheet.

BGE

	Rates	Maturity Date	December 31, 2021	December 31, 2020
Long-term debt				
Unsecured notes	2.25 % - 6.35 %	2022 - 2050	$ 4,000	$ 3,700
Total long-term debt			4,000	3,700
Unamortized debt discount and premium, net			(12)	(12)
Unamortized debt issuance costs			(27)	(24)
Long-term debt due within one year			(250)	(300)
Long-term debt			$ 3,711	$ 3,364

PHI

	Rates	Maturity Date	December 31, 2021	December 31, 2020
Long-term debt				
First mortgage bonds[a]	0.14 % - 7.90 %	2022 - 2051	$ 6,672	$ 6,086
Senior unsecured notes	7.45 %	2032	185	185
Unsecured tax-exempt bonds	0.12 % - 1.70 %	2022 - 2024	143	143
Medium-terms notes (unsecured)	7.72 %	2027	10	10
Transition bonds	5.55 %	2021	—	21
Finance leases	3.54 %	2022 - 2029	74	50
Other[b]	7.28 % - 7.49 %	2022	—	1
Total long-term debt			7,084	6,496
Unamortized debt discount and premium, net			4	4
Unamortized debt issuance costs			(36)	(28)
Fair value adjustment			495	534
Long-term debt due within one year			(399)	(347)
Long-term debt			$ 7,148	$ 6,659

(a) Substantially all of Pepco's, DPL's, and ACE's assets are subject to the liens of their respective mortgage indentures.
(b) The amount in the Other category was less than 1 million as of December 31, 2021.

Pepco

	Rates	Maturity Date	December 31, 2021	December 31, 2020
Long-term debt				
First mortgage bonds[a]	2.32 % - 7.90 %	2022 - 2051	$ 3,350	$ 3,075
Unsecured tax-exempt bonds	1.70 %	2022	110	110
Finance leases	3.54 %	2025 - 2029	26	17
Other[b]	7.28 % - 7.49 %	2022	—	1
Total long-term debt			3,486	3,203
Unamortized debt discount and premium, net			2	2
Unamortized debt issuance costs			(43)	(40)
Long-term debt due within one year			(313)	(3)
Long-term debt			$ 3,132	$ 3,162

(a) Substantially all of Pepco's assets are subject to the lien of its mortgage indenture.
(b) The amount in the Other category was less than 1 million as of December 31, 2021.

DPL

	Rates	Maturity Date	December 31, 2021	December 31, 2020
Long-term debt				
First mortgage bonds[(a)(b)]	0.14 % - 4.27 %	2023 - 2051	$ 1,749	$ 1,624
Unsecured tax-exempt bonds	0.12 % - 0.13 %	2024	33	33
Medium-terms notes (unsecured)	7.72 %	2027	10	10
Finance leases	3.54 %	2025 - 2029	29	20
Total long-term debt			1,821	1,687
Unamortized debt discount and premium, net			—	1
Unamortized debt issuance costs			(11)	(11)
Long-term debt due within one year			(83)	(82)
Long-term debt			$ 1,727	$ 1,595

(a) Substantially all of DPL's assets are subject to the lien of its mortgage indenture.
(b) On November 16, 2021, DPL entered into a purchase agreement of First Mortgage Bonds of $125 million at 3.06% due on February 15, 2052. The closing date of the issuance occurred on February 15, 2022.

ACE

	Rates	Maturity Date	December 31, 2021	December 31, 2020
Long-term debt				
First mortgage bonds[(a)(b)]	2.25 % - 5.80 %	2024 - 2050	$ 1,573	$ 1,387
Transition bonds	5.55 %	2021	—	21
Finance leases	3.54 %	2022 - 2029	19	13
Total long-term debt			1,592	1,421
Unamortized debt discount and premium, net			(1)	(1)
Unamortized debt issuance costs			(9)	(7)
Long-term debt due within one year			(3)	(261)
Long-term debt			$ 1,579	$ 1,152

(a) Substantially all of ACE's assets are subject to the lien of its mortgage indenture.
(b) On November 16, 2021, ACE entered into a purchase agreement of First Mortgage Bonds of $25 million and $150 million at 2.27% and 3.06% due on February 15, 2032 and February 15, 2052, respectively. The closing date of the issuance occurred on February 15, 2022.

Long-term debt maturities at the Registrants in the periods 2022 through 2026 and thereafter are as follows:

Year	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2022	$ 3,373	$ —	$ 350	$ 250	$ 399	$ 313	$ 83	$ 3
2023	865	—	50	300	512	4	505	3
2024	818	250	—	—	562	404	5	153
2025	2,223	—	350	—	162	4	5	153
2026	1,725	500	—	350	11	4	4	3
Thereafter	29,752 (a)	9,342 (b)	3,684 (c)	3,100	5,438	2,757	1,219	1,277
Total	$ 38,756	$ 10,092	$ 4,434	$ 4,000	$ 7,084	$ 3,486	$ 1,821	$ 1,592

(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.

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) entered into intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes receivable at Exelon Corporate from Generation. As of December 31, 2021 and 2020, Exelon Corporate had $319 million and $324 million, respectively, recorded to intercompany notes receivable from Generation. In connection with the separation, on January 31, 2022, Exelon Corporate received cash from Generation of $258 million to settle the intercompany loan.

Debt Covenants

As of December 31, 2021, the Registrants are in compliance with debt covenants.

Nonrecourse Debt

Exelon, through Generation, has issued nonrecourse debt financing, in which approximately $2 billion of generating assets have been pledged as collateral as of December 31, 2021. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against Exelon 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, 2021 and December 31, 2020, approximately $435 million and $460 million were outstanding, respectively. In addition, letters of credit were issued to support Generation's equity investment in the project with $37 million outstanding as of December 31, 2021. In December 2017, Exelon’s interests in Antelope Valley were contributed to and are pledged as collateral for the CR financing structures referenced below.

Continental Wind, LLC. In September 2013, Continental Wind, an indirect subsidiary of Exelon, 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, 2021 and December 31, 2020, approximately $380 million and $415 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, 2021, the Continental Wind letter of credit facility had $115 million in letters of credit outstanding related to the project.

In 2017, Exelon’s interests in Continental Wind were contributed to CRP. Refer to Note 23 - Variable Interest Entities for additional information on CRP.

Renewable Power Generation. In March 2016, RPG, an indirect subsidiary of Exelon, 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, 2021 and December 31, 2020, approximately $90 million and $95 million were outstanding, respectively.

In 2017, Exelon’s interests in RPG were contributed to CRP. Refer to Note 23 - Variable Interest Entities for additional information on CRP.

SolGen, LLC. In September 2016, SolGen, an indirect subsidiary of Exelon, issued $150 million aggregate principal amount of a nonrecourse senior secured notes. The net proceeds were distributed to Generation for general business purposes. 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 sale was completed on March 31, 2021 in which the buyer assumed the $125 million outstanding debt. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information on the sale agreement.

Constellation Renewables. In November 2017, CR, an indirect subsidiary of Exelon, 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, CR 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, CR 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 2.50%, subject to a 1% LIBOR floor with interest payable quarterly. In addition to the financing, CR 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. Exelon’s interests in CRP and Antelope Valley remained contributed to and are pledged as collateral for this financing. As of December 31, 2021 and December 31, 2020, $735 million and $750 million was outstanding, respectively. See Note 23 — Variable Interest Entities for additional information on CRP and Note 16 — Derivative Financial Instruments for additional information on interest rate swaps.

West Medway II, LLC. On May 13, 2021, West Medway II, LLC (West Medway II), an indirect subsidiary of Exelon, entered into a financing agreement for a $150 million nonrecourse senior secured term loan credit facility with a maturity date of March 31, 2026. The term loan bears interest at an average blended interest rate of LIBOR plus 3%, paid quarterly. In addition to the financing, West Medway II, entered into interest rate swaps with an initial notional amount of $113 million at an interest rate of 0.61%, paid quarterly, to manage a portion of the interest rate exposure in connection with the financing. The net proceeds were distributed to Generation for general corporate purposes. Exelon’s interests in West Medway II, were pledged as collateral for this financing. As of December 31, 2021, approximately $135 million was outstanding. See 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, 2021 and 2020. The Registrants have no financial liabilities classified as Level 1.

The carrying amounts of the Registrants' short-term liabilities as presented in their Consolidated Balance Sheets are representative of their fair value (Level 2) because of the short-term nature of these instruments.

	December 31, 2021				December 31, 2020			
	Carrying Amount	Fair Value			Carrying Amount	Fair Value		
		Level 2	Level 3	Total		Level 2	Level 3	Total
Long-Term Debt, including amounts due within one year[(a)]								
Exelon	$ 38,697	$ 40,282	$ 3,310	$ 43,592	$ 36,912	$ 40,688	$ 3,064	$ 43,752
ComEd	9,773	11,305	—	11,305	8,983	11,117	—	11,117
PECO	4,197	4,740	50	4,790	3,753	4,553	50	4,603
BGE	3,961	4,406	—	4,406	3,664	4,366	—	4,366
PHI	7,547	5,970	2,167	8,137	7,006	6,099	1,806	7,905
Pepco	3,445	3,201	975	4,176	3,165	3,336	748	4,084
DPL	1,810	1,426	552	1,978	1,677	1,484	455	1,939
ACE	1,582	1,091	641	1,732	1,413	1,018	602	1,620
Long-Term Debt to Financing Trusts								
Exelon	$ 390	$ —	$ 470	$ 470	$ 390	$ —	$ 467	$ 467
ComEd	205	—	248	248	205	—	246	246
PECO	184	—	222	222	184	—	221	221
SNF Obligation								
Exelon	$ 1,210	$ 1,060	$ —	$ 1,060	$ 1,208	$ 909	$ —	$ 909

(a) Includes unamortized debt issuance costs, unamortized debt discount and premium, net, purchase accounting fair value adjustments, and finance lease liabilities which are not fair valued. Refer to Note 17 — Debt and Credit Agreements for unamortized debt issuance costs, unamortized debt discount and premium, net, and purchase accounting fair value adjustments and Note 11 — Leases for finance lease liabilities.

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, 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	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, 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	The carrying amount is derived from a contract with the DOE to provide for disposal of SNF from certain of Exelon’s nuclear generating stations. See Note 19 — Commitments and Contingencies for further details. 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 Exelon’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.

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, 2021 and 2020:

Exelon

	As of December 31, 2021					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]	$ 643	$ —	$ —	$ —	$ 643	$ 686	$ —	$ —	$ —	$ 686
NDT fund investments										
Cash equivalents[b]	465	116	—	—	581	210	95	—	—	305
Equities	4,564	1,805	—	1,645	8,014	3,886	2,077	—	1,562	7,525
Fixed income										
Corporate debt[c]	—	1,145	286	—	1,431	—	1,485	285	—	1,770
U.S. Treasury and agencies	2,193	30	—	—	2,223	1,871	126	—	—	1,997
Foreign governments	—	60	—	—	60	—	56	—	—	56
State and municipal debt	—	26	—	—	26	—	101	—	—	101
Other	29	23	—	1,449	1,501	—	41	—	961	1,002
Fixed income subtotal	2,222	1,284	286	1,449	5,241	1,871	1,809	285	961	4,926
Private credit	—	—	178	624	802	—	—	212	629	841
Private equity	—	—	—	673	673	—	—	—	504	504
Real estate	—	—	—	864	864	—	—	—	679	679
NDT fund investments subtotal[d][e]	7,251	3,205	464	5,255	16,175	5,967	3,981	497	4,335	14,780
Rabbi trust investments										
Cash equivalents	63	—	—	—	63	60	—	—	—	60
Mutual funds	105	—	—	—	105	91	—	—	—	91
Fixed income	—	10	—	—	10	—	11	—	—	11
Life insurance contracts	—	99	38	—	137	—	87	34	—	121
Rabbi trust investments subtotal	168	109	38	—	315	151	98	34	—	283
Investments in equities[f]	43	—	—	—	43	195	—	—	—	195
Commodity derivative assets										
Economic hedges	3,017	7,223	3,899	—	14,139	745	1,914	1,599	—	4,258
Proprietary trading	—	19	8	—	27	—	17	27	—	44
Effect of netting and allocation of collateral[g][h]	(2,108)	(6,177)	(2,769)	—	(11,054)	(607)	(1,597)	(905)	—	(3,109)
Commodity derivative assets subtotal	909	1,065	1,138	—	3,112	138	334	721	—	1,193
DPP consideration	—	365	—	—	365	—	639	—	—	639
Total assets	9,014	4,744	1,640	5,255	20,653	7,137	5,052	1,252	4,335	17,776
Liabilities										
Commodity derivative liabilities										
Economic hedges	(2,201)	(6,870)	(4,184)	—	(13,255)	(682)	(1,928)	(1,655)	—	(4,265)
Proprietary trading	—	(18)	(2)	—	(20)	—	(21)	(4)	—	(25)
Effect of netting and allocation of collateral[g][h]	2,189	6,642	2,735	—	11,566	540	1,918	1,067	—	3,525
Commodity derivative liabilities subtotal	(12)	(246)	(1,451)	—	(1,709)	(142)	(31)	(592)	—	(765)
Deferred compensation obligation	—	(154)	—	—	(154)	—	(145)	—	—	(145)
Total liabilities	(12)	(400)	(1,451)	—	(1,863)	(142)	(176)	(592)	—	(910)
Total net assets	$ 9,002	$ 4,344	$ 189	$ 5,255	$ 18,790	$ 6,995	$ 4,876	$ 660	$ 4,335	$ 16,866

(a) Excludes cash of $881 million and $409 million as of December 31, 2021 and 2020, respectively, and restricted cash of $95 million and $59 million as of December 31, 2021 and 2020, respectively, and includes long-term restricted cash of $44 million and $53 million as of December 31, 2021 and 2020, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets.

(b) Includes $116 million of cash received from outstanding repurchase agreements as of both December 31, 2021 and 2020, 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 $(55) million and $(62) million as of December 31, 2021 and 2020, respectively, held in an investment vehicle primarily to hedge the equity option component of its convertible debt.

(d) Includes net derivative liabilities of $1 million and net derivative assets of $2 million, which have total notional amounts of $687 million and $1,043 million as of December 31, 2021 and 2020, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the periods ended and do not represent the amount of Exelon's exposure to credit or market loss.

(e) Excludes net liabilities of $111 million and $181 million as of December 31, 2021 and 2020, respectively, which include certain derivative assets that have notional amounts of $182 million and $104 million as of December 31, 2021 and 2020, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.

(f) Includes equity investments which were previously designated as equity investments without readily determinable fair values but are now publicly traded and therefore have readily determinable fair values. The first investment became publicly traded in the fourth quarter of 2020. The fair value of these investments is recorded in Other current assets in Exelon's Consolidated Balance Sheets based on the quoted market prices of the stocks as of the respective balance sheet date. Unrealized (losses)/gains of $(160) million and $186 million were recorded in Other, net in Exelon's Consolidated Statement of Operations and Comprehensive Income for the years ended December 31, 2021 and 2020, respectively.

(g) Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled $81 million, $465 million, and $(34) million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of December 31, 2021. 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.

(h) Includes $897 million held and $209 million posted of variation margin with the exchanges as of December 31, 2021 and 2020, respectively.

As of December 31, 2021, Exelon has outstanding commitments to invest in private credit, private equity, and real estate investments of approximately $306 million, $171 million, and $459 million, respectively. These commitments will be funded by the existing NDT funds.

Exelon held investments without readily determinable fair values with carrying amounts of $44 million and $73 million as of December 31, 2021 and 2020, respectively. Changes in fair value, cumulative adjustments, and impairments were not material for the years ended December 31, 2021 and 2020.

ComEd, PECO, and BGE

	ComEd				PECO				BGE			
As of December 31, 2021	**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]	$ 237	$ —	$ —	$ 237	$ 9	$ —	$ —	$ 9	$ —	$ —	$ —	$ —
Rabbi trust investments												
Mutual funds	—	—	—	—	11	—	—	11	14	—	—	14
Life insurance contracts	—	—	—	—	—	16	—	16	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	11	16	—	27	14	—	—	14
Total assets	237	—	—	237	20	16	—	36	14	—	—	14
Liabilities												
Mark-to-market derivative liabilities[b]	—	—	(219)	(219)	—	—	—	—	—	—	—	—
Deferred compensation obligation	—	(10)	—	(10)	—	(9)	—	(9)	—	(7)	—	(7)
Total liabilities	—	(10)	(219)	(229)	—	(9)	—	(9)	—	(7)	—	(7)
Total net assets (liabilities)	$ 237	$ (10)	$ (219)	$ 8	$ 20	$ 7	$ —	$ 27	$ 14	$ (7)	$ —	$ 7

	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

(a) ComEd excludes cash of $105 million and $83 million as of December 31, 2021 and 2020, respectively, and restricted cash of $42 million and $37 million as of December 31, 2021 and 2020, respectively, and includes long-term restricted cash of $43 million as of both December 31, 2021 and 2020, which is reported in Other deferred debits in the Consolidated Balance Sheets. PECO excludes cash of $35 million and $18 million as of December 31, 2021 and 2020, respectively. BGE excludes cash of $51 million and $24 million as of December 31, 2021 and 2020, respectively, and restricted cash of $4 million and $1 million as of December 31, 2021 and 2020, respectively.

(b) The Level 3 balance consists of the current and noncurrent liability of $18 million and $201 million, respectively, as of December 31, 2021 and $33 million and $268 million, respectively, as of December 31, 2020 related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

PHI, Pepco, DPL, and ACE

	As of December 31, 2021				As of December 31, 2020			
PHI	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets								
Cash equivalents[(a)]	$ 110	$ —	$ —	$ 110	$ 86	$ —	$ —	$ 86
Rabbi trust investments								
Cash equivalents	59	—	—	59	55	—	—	55
Mutual funds	14	—	—	14	14	—	—	14
Fixed income	—	10	—	10	—	11	—	11
Life insurance contracts	—	27	35	62	—	26	34	60
Rabbi trust investments subtotal	73	37	35	145	69	37	34	140
Total assets	183	37	35	255	155	37	34	226
Liabilities								
Deferred compensation obligation	—	(18)	—	(18)	—	(17)	—	(17)
Total liabilities	—	(18)	—	(18)	—	(17)	—	(17)
Total net assets	$ 183	$ 19	$ 35	$ 237	$ 155	$ 20	$ 34	$ 209

	Pepco				DPL				ACE			
As of December 31, 2021	**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)]	$ 31	$ —	$ —	$ 31	$ 43	$ —	$ —	$ 43	$ —	$ —	$ —	$ —
Rabbi trust investments												
Cash equivalents	58	—	—	58	—	—	—	—	—	—	—	—
Life insurance contracts	—	27	35	62	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	58	27	35	120	—	—	—	—	—	—	—	—
Total assets	89	27	35	151	43	—	—	43	—	—	—	—
Liabilities												
Deferred compensation obligation	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total liabilities	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total net assets	$ 89	$ 25	$ 35	$ 149	$ 43	$ —	$ —	$ 43	$ —	$ —	$ —	$ —

	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

(a) PHI excludes cash of $100 million and $74 million as of December 31, 2021 and 2020, respectively, and restricted cash of $3 million and none as of December 31, 2021 and 2020, respectively, and includes long-term restricted cash of none and $10 million as of December 31, 2021 and 2020, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. Pepco excludes cash of $34 million and $30 million as of December 31, 2021 and 2020, respectively, and restricted cash of $3 million and none as of December 31, 2021 and 2020, respectively. DPL excludes cash of $28 million and $15 million as of December 31, 2021 and 2020, respectively. ACE excludes cash of $29 million and $17 million as of December 31, 2021 and 2020, respectively, and includes long-term restricted cash of none and $10 million as of December 31, 2021 and 2020, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets.

Reconciliation of Level 3 Assets and Liabilities

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2021 and 2020:

	Exelon				ComEd	PHI and Pepco
For the year ended December 31, 2021	NDT Fund Investments	Mark-to-Market Derivatives	Life Insurance Contracts	Total	Mark-to-Market Derivatives	Life Insurance Contracts
Balance as of January 1, 2021	$ 497	$ 129	$ 34	$ 660	$ (301)	$ 34
Total realized / unrealized gains (losses)						
Included in net income	5	(812) (a)	3	(804)	—	3
Included in regulatory assets/liabilities	19	82	—	101	82 (b)	—
Change in collateral	—	(196)	—	(196)	—	—
Purchases, sales, and settlements						
Purchases	4	162	—	166	—	—
Sales	—	(10)	—	(10)	—	—
Settlements	(61)	—	(2)	(63)	—	(2)
Transfers into Level 3	—	19 (c)	3	22	—	—
Transfers out of Level 3	—	313 (c)	—	313	—	—
Balance as of December 31, 2021	$ 464	$ (313)	$ 38	$ 189	$ (219)	$ 35
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of December 31, 2021	$ 5	$ (1,222)	$ 3	(1,214)	$ —	$ 3

	Exelon				ComEd	PHI and Pepco
For the year ended December 31, 2020	**NDT Fund Investments**	**Mark-to-Market Derivatives**	**Life Insurance Contracts**	**Total**	**Mark-to-Market Derivatives**	**Life Insurance Contracts**
Balance as of January 1, 2020	$ 511	$ 516	$ 41	$ 1,068	$ (301)	$ 41
Total realized / unrealized gains (losses)						
Included in net income	2	(414) [a]	3	(409)	—	3
Included in regulatory assets/liabilities	21	—	—	21	— [b]	—
Change in collateral	—	(53)	—	(53)	—	—
Purchases, sales, and settlements						
Purchases	8	143	—	151	—	—
Sales	—	(27)	—	(27)	—	—
Settlements	(45)	—	(10)	(55)	—	(10)
Transfers into Level 3	—	(12) [c]	—	(12)	—	—
Transfers out of Level 3	—	(24) [c]	—	(24)	—	—
Balance as of December 31, 2020	$ 497	$ 129	$ 34	$ 660	$ (301)	$ 34
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of December 31, 2020	$ 2	$ 6	$ 3	$ 11	$ —	$ 3

(a) Includes an addition of $410 million for realized losses and a reduction of $420 million for realized gains due to the settlement of derivative contracts for the years ended December 31, 2021 and 2020, respectively.

(b) Includes $62 million of increases in fair value and an increase for realized losses due to settlements of $20 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2021. 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.

(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, 2021 and 2020:

	Exelon				PHI and Pepco
	Operating Revenues	**Purchased Power and Fuel**	**Operating and Maintenance**	**Other, net**	**Operating and Maintenance**
Total (losses) gains included in net income for the year ended December 31, 2021	$ (1,343)	$ 531	$ 3	$ 5	$ 3
Total unrealized (losses) gains for the year ended December 31, 2021	(1,577)	355	3	5	3

	Exelon				PHI and Pepco
	Operating Revenues	**Purchased Power and Fuel**	**Operating and Maintenance**	**Other, net**	**Operating and Maintenance**
Total (losses) gains included in net income for the year ended December 31, 2020	$ (404)	$ (10)	$ 3	$ 2	$ 3
Total unrealized (losses) gains for the year ended December 31, 2020	(31)	37	3	2	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). The trust fund investments have been established to satisfy Generation'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 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 is 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 on the underlying securities and are not classified within the fair value hierarchy. These investments can typically 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 has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Exelon selectively corroborates 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 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 of the underlying investments from sources with professional qualifications, typically using a combination of market based comparable data and discounted cash flows. These valuation inputs are unobservable. Certain real estate investments 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. The remaining liquid real estate investments are generally redeemable from the investment vehicle quarterly, with 30 to 90 days of notice. 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.

Exelon evaluated its NDT portfolios for the existence of significant concentrations of credit risk as of December 31, 2021. 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, 2021, there were no significant concentrations (generally defined as greater than 10 percent) of risk in the 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, 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). Exelon holds 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). Exelon has DPP consideration for the sale of certain receivables of retail electricity. 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 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. The Level 3 balance related to Generation generally consists of forward sales and purchases of power and natural gas and certain transmission congestion contracts. Exelon 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, Exelon 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 $3.33 and $0.53 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 as of December 31, 2021	Fair Value as of December 31, 2020	Valuation Technique	Unobservable Input	2021 Range & Arithmetic Average				2020 Range & Arithmetic Average			
Mark-to-market derivatives—Economic hedges (Exelon)[(a)(b)]	$ (66)	$ 245	Discounted Cash Flow	Forward power price	$8.86	-	$481	$55	$2.25	-	$163	$30
				Forward gas price	$1.69	-	$17	$3.50	$1.57	-	$7.88	$2.59
			Option Model	Volatility percentage	24%	-	284%	56%	11%	-	237%	32%
Mark-to-market derivatives (Exelon and ComEd)	$ (219)	$ (301)	Discounted Cash Flow	Forward heat rate[(c)]	9x	-	10x	9.13x	8x	-	9x	8.85x
				Marketability reserve	3%	-	7%	4.77%	3%	-	8%	4.93%
				Renewable factor	92%	-	120%	97%	91%	-	123%	99%

(a) These positions relate to Generation and 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 (received)/posted on level three positions of $(34) million and $162 million as of December 31, 2021 and December 31, 2020, respectively.

(c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.

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 Exelon'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 Exelon the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Exelon 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, 2021:

Description	Exelon	PHI	Pepco	DPL	ACE
Total commitments	$ 513	$ 320	$ 120	$ 89	$ 111
Remaining commitments[(a)]	68	58	48	6	4

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

In addition, Exelon is committed to develop or to assist in the commercial development of approximately 37 MWs of new solar generation in Maryland, District of Columbia, and Delaware at an estimated cost of approximately $135 million. Investment costs, which are expected to be primarily capital in nature, are recognized as incurred and recorded in Exelon's financial statements. As of December 31, 2021, approximately 33 MWs of new generation were developed and Exelon incurred costs of $121 million. Development of the remaining 4 MWs of new generation will be completed by Generation in 2022. Approximately 30 MWs of the new generation developed was part of Generation's first quarter 2021 sale of a significant portion of its solar business. Refer to Note 2 - Mergers, Acquisitions and Dispositions for additional information on the solar business. 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 DEPSC in 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, 2021, representing commitments potentially triggered by future events were as follows:

		Expiration within					
Exelon	**Total**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027 and beyond**
Letters of credit	$ 2,397	$ 2,296	$ 101	$ —	$ —	$ —	$ —
Surety bonds[a]	1,008	989	17	2	—	—	—
Financing trust guarantees	378	—	—	—	—	—	378
Guaranteed lease residual values[b]	31	—	5	6	6	5	9
Total commercial commitments	$ 3,814	$ 3,285	$ 123	$ 8	$ 6	$ 5	$ 387
ComEd							
Letters of credit	$ 7	$ 7	$ —	$ —	$ —	$ —	$ —
Surety bonds[a]	17	15	—	2	—	—	—
Financing trust guarantees	200	—	—	—	—	—	200
Total commercial commitments	$ 224	$ 22	$ —	$ 2	$ —	$ —	$ 200
PECO							
Letters of credit	$ 1	$ 1	$ —	$ —	$ —	$ —	$ —
Surety bonds[a]	2	2	—	—	—	—	—
Financing trust guarantees	178	—	—	—	—	—	178
Total commercial commitments	$ 181	$ 3	$ —	$ —	$ —	$ —	$ 178
BGE							
Letters of credit	$ 2	$ 2	$ —	$ —	$ —	$ —	$ —
Surety bonds[a]	3	3	—	—	—	—	—
Total commercial commitments	$ 5	$ 5	$ —	$ —	$ —	$ —	$ —
PHI							
Surety bonds[a]	$ 23	$ 23	$ —	$ —	$ —	$ —	$ —
Guaranteed lease residual values[b]	31	—	5	6	6	5	9
Total commercial commitments	$ 54	$ 23	$ 5	$ 6	$ 6	$ 5	$ 9
Pepco							
Surety bonds[a]	$ 14	$ 14	$ —	$ —	$ —	$ —	$ —
Guaranteed lease residual values[c]	10	—	1	2	2	2	3
Total commercial commitments	$ 24	$ 14	$ 1	$ 2	$ 2	$ 2	$ 3
DPL							
Surety bonds[a]	$ 5	$ 5	$ —	$ —	$ —	$ —	$ —
Guaranteed lease residual values[b]	13	—	2	3	2	2	4
Total commercial commitments	$ 18	$ 5	$ 2	$ 3	$ 2	$ 2	$ 4
ACE							
Surety bonds[a]	$ 4	$ 4	$ —	$ —	$ —	$ —	$ —
Guaranteed lease residual values[b]	8	—	2	1	2	1	2
Total commercial commitments	$ 12	$ 4	$ 2	$ 1	$ 2	$ 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 $75 million guaranteed by Exelon and PHI, of which $25 million, $31 million, and $19 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)

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, 2021, the current liability limit per incident is $13.5 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 $13.1 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 $2.8 billion, however any amounts payable under this secondary layer would be capped at $413 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 $13.5 billion limit for a single incident.

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. Generation's portion of the annual distribution declared by NEIL is estimated to be $113 million for 2021, and was $75 million and $136 million for 2020 and 2019, respectively. The distributions were recorded as a reduction to Operating and maintenance expense within Exelon’s Consolidated Statements of Operations and Comprehensive Income.

Spent Nuclear Fuel Obligation (Exelon)

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. 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. FitzPatrick also has a separate settlement agreement in place with the DOE which was established in 2021 to provide for 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 $1,492 million through December 31, 2021 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 $1,294 million. As of December 31, 2021 and 2020, 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, 2021	December 31, 2020
DOE receivable - current[(a)]	$ 241	$ 129
DOE receivable - noncurrent[(b)]	85	70
Amounts owed to co-owners[(c)]	(35)	(23)

(a) Recorded in Other accounts receivable.
(b) Recorded in Deferred debits and other assets, other.
(c) Recorded in Other accounts receivable. 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 as of December 31, 2021 and 2020:

	December 31, 2021	December 31, 2020
Former ComEd units[(a)]	$ 1,083	$ 1,082
Fitzpatrick[(b)]	127	126
Total SNF Obligation	$ 1,210	$ 1,208

(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 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, 2021 was 0.051% for the deferred amount transferred from ComEd and 0.041% for the deferred FitzPatrick amount.

The following table summarizes sites for which Exelon does 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 (All Registrants). ComEd, PECO, BGE, and DPL have identified sites where former MGP or gas purification activities have or may have resulted in actual site contamination. For 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 2027.
- PECO has 6 sites that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 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, 2021 and 2020, the Registrants had accrued the following undiscounted amounts for environmental liabilities in Other current liabilities and Other deferred credits and other liabilities in their respective Consolidated Balance Sheets:

	December 31, 2021		December 31, 2020	
	Total environmental investigation and remediation liabilities	Portion of total related to MGP investigation and remediation	Total environmental investigation and remediation liabilities	Portion of total related to MGP investigation and remediation
Exelon	$ 469	$ 303	$ 483	$ 314
ComEd	279	279	293	293
PECO	22	20	23	21
BGE	6	4	2	—
PHI	42	—	44	—
Pepco	40	—	42	—
DPL	1	—	1	—
ACE	1	—	1	—

Cotter Corporation (Exelon). The EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. In 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. Including Cotter, there are three PRPs participating in the West Lake Landfill remediation proceeding. Investigation by Generation has identified a number of other parties who also may be PRPs and could be liable to contribute to the final remedy. Further investigation is ongoing.

In September 2018, the EPA issued its Record of Decision Amendment (RODA) for the selection of a final remedy. The RODA modified the remedy previously selected by EPA in its 2008 Record of Decision (ROD). While the ROD required only that the radiological materials and other wastes at the site be capped, the 2018 RODA requires partial excavation of the radiological materials in addition to the previously selected capping remedy. The RODA also allows for variation in depths of excavation depending on radiological concentrations. The EPA and the PRPs have entered into a Consent Agreement to perform the Remedial Design, which is expected to be completed in late 2024. 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 $290 million, including cost escalation on an undiscounted basis, which would be allocated among the final group of PRPs. Exelon 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 Exelon'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.

One of the other PRPs has indicated it will be making a contribution claim against Cotter for costs that it has incurred to prevent a subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, Exelon does not possess sufficient information to assess this claim and therefore are unable to estimate a range of loss, if any. As such, no liability has been recorded for the potential contribution claim.

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 and Feasibility Study (RI/FS). The purpose of this RI/FS is to define the nature and extent of any groundwater contamination from the West Lake Landfill site and evaluate remedial alternatives. Exelon estimates the undiscounted cost for the groundwater RI/FS to be approximately $40 million. Exelon 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 Exelon cannot predict the likelihood or the extent to which, if any, remediation activities may be required and therefore cannot estimate a reasonably possible range of loss for response costs beyond those associated with the RI/FS component.

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 (Formerly Utilized Sites Remedial Action Program). Pursuant to a series of annual agreements since 2011, the DOJ and the PRPs have tolled the statute of limitations until February 28, 2022 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. In December 2021, a good faith offer was submitted to the government and negotiations are expected to commence in the first quarter of 2022. Exelon 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, 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, 2022. After completion and approval of the FS, DOEE will prepare a Proposed Plan for public comment and then issue a ROD identifying any further response actions determined to be necessary. Exelon, PHI, and Pepco, have determined that a loss associated with this matter is probable and have accrued an estimated liability, which is included in the table above.

Anacostia River Tidal Reach (Exelon, PHI, and Pepco). Contemporaneous with the Benning Road site RI/FS being performed by Pepco and Generation, DOEE and National Park Service ("NPS") have been conducting a separate RI/FS focused on the entire tidal reach of the Anacostia River extending from just north of the Maryland-District of Columbia boundary line to the confluence of the Anacostia and Potomac Rivers. The river-wide RI incorporated the results of the river sampling performed by Pepco and Pepco Energy Services as part of the Benning RI/FS, as well as similar sampling efforts conducted by owners of other sites adjacent to this segment of the river and supplemental river sampling conducted by DOEE’s contractor. In April 2018, DOEE released a draft RI report for public review and comment. Pepco submitted written comments to the draft RI and participated in a public hearing.

Pepco has determined that it is probable that costs for remediation will be incurred and recorded a liability in the third quarter 2019 for management’s best estimate of its share of those costs. On September 30, 2020, DOEE released its Interim ROD. The Interim ROD reflects an adaptive management approach which will require several identified “hot spots” in the river to be addressed first while continuing to conduct studies and to monitor the river to evaluate improvements and determine potential future remediation plans. The adaptive management process chosen by DOEE is less intrusive, provides more long-term environmental certainty, is less costly, and allows for site specific remediation plans already underway, including the plan for the Benning Road site to proceed to conclusion. Pepco concluded that incremental exposure remains reasonably possible, but management cannot reasonably estimate a range of loss beyond the amounts recorded, which are included in the table above.

On July 12, 2021, DOEE and NPS held a virtual meeting with the PRP's in response to a General Notice Letter sent by each agency inviting the PRP's to participate in discussions, which PEPCO attended.

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). Exelon 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, 2021 and December 31, 2020, Exelon had recorded estimated liabilities of approximately $81 million and $89 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2021, approximately $17 million of this amount related to 211 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.

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, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at 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 DEPSC 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.

Deferred Prosecution Agreement (DPA) and Related Matters (Exelon and ComEd). Exelon and ComEd received a grand jury subpoena in the second quarter of 2019 from the U.S. Attorney's Office for the Northern District of Illinois (USAO) requiring production of information concerning their lobbying activities in the State of Illinois. On October 4, 2019, Exelon and ComEd received a second grand jury subpoena from the USAO requiring production of records of any communications with certain individuals and entities. On October 22, 2019, the SEC notified Exelon and ComEd that it had also opened an investigation into their lobbying activities. On July 17, 2020, ComEd entered into a DPA with the USAO to resolve the USAO investigation. Under the DPA, the USAO filed a single charge alleging that ComEd improperly gave and offered to give jobs, vendor subcontracts, and payments associated with those jobs and subcontracts for the benefit of the Speaker of the Illinois House of Representatives and the Speaker's associates, with the intent to influence the Speaker's action regarding legislation affecting ComEd's interests. The DPA provides that the USAO will defer any prosecution of such charge and any other criminal or civil case against ComEd in connection with the matters identified therein for a three-year period subject to certain obligations of ComEd, including payment to the U.S. Treasury of $200 million, which was paid in November 2020. Exelon was not made a party to the DPA, and therefore the investigation by the USAO into Exelon's activities ended with no charges being brought against Exelon. The SEC's investigation remains ongoing and Exelon and ComEd have cooperated fully and intend to continue to cooperate fully with the SEC. Exelon and ComEd cannot predict the outcome of the SEC investigation. No loss contingency has been reflected in Exelon's and ComEd's consolidated financial statements with respect to the SEC investigation, as this contingency is neither probable nor reasonably estimable at this time.

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

- Four putative class action lawsuits against ComEd and Exelon were filed in federal court on behalf of ComEd customers in the third quarter of 2020 alleging, among other things, civil violations of federal racketeering laws. In addition, the Citizens Utility Board (CUB) filed a motion to intervene in these cases on October 22, 2020 which was granted on December 23, 2020. On 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. However, the Potter plaintiffs voluntarily dismissed their complaint without prejudice on April 5, 2021. ComEd and Exelon moved to dismiss the consolidated class action complaint and CUB's complaint on February 4, 2021 and briefing was completed on March 22, 2021. On March 25, 2021, the parties agreed, along with state court plaintiffs, discussed below, to jointly engage in mediation. The parties participated in a one-day mediation on June 7, 2021 but no settlement was reached. On September 9, 2021, the federal court granted Exelon's and ComEd's motion to dismiss and dismissed the plaintiffs' and CUB's federal law claim with prejudice. The federal court also dismissed the related state law claims made by the federal plaintiffs and CUB on jurisdictional grounds. Plaintiffs have appealed the ruling to the Seventh Circuit Court of Appeals. Plaintiffs' opening appeal brief was filed on January 14, 2022. Exelon and ComEd have requested an extension until March 7, 2022 to file their response brief. Plaintiff's reply brief will be due approximately 21 days thereafter. Plaintiffs also refiled their state law claims in state court and have moved to consolidate that action with the already pending consumer state court class action, discussed below. CUB also refiled its state law claims in state court.

- Three putative class action lawsuits against ComEd and Exelon were filed in Illinois state court in the third quarter of 2020 seeking restitution and compensatory damages on behalf of ComEd customers. The cases were consolidated into a single action in October of 2020. In November 2020, CUB filed a motion to intervene in the cases pursuant to an Illinois statute allowing CUB to intervene as a party or otherwise participate on behalf of utility consumers in any proceeding which affects the interest of utility consumers. On November 23, 2020, the court allowed CUB's intervention, but denied its request to stay these cases. Plaintiffs subsequently filed a consolidated complaint, and ComEd and Exelon filed a motion to dismiss on jurisdictional and substantive grounds on January 11, 2021. Briefing on that motion was completed on March 2, 2021. The parties agreed, on March 25, 2021, along with the federal court plaintiffs discussed above, to jointly engage in mediation. The parties participated in a one-day mediation on June 7, 2021 but no settlement was reached. On December 23, 2021, the state court granted ComEd and Exelon’s motion to dismiss with prejudice. On December 30, 2021, plaintiffs filed a motion to reconsider that dismissal and for permission to amend their complaint. The court denied the plaintiffs' motion on January 21, 2022. Plaintiffs have appealed the court's ruling dismissing their complaint to the First District Court of Appeals. On February 15, 2022, Exelon and ComEd moved to dismiss the federal plaintiffs' refiled state law claims, seeking dismissal on the same legal grounds as those asserted in their motion to dismiss the original state court plaintiffs' complaint. The parties agreed to submit their motion to dismiss briefing as a package, which included Exelon' and ComEd's motion, plaintiffs' response, and Exelon's and ComEd's reply, in order to facilitate a speedy resolution by the court. The court granted dismissal of the refiled state claims on February 16, 2022. The original federal plaintiffs filed their notice of appeal of that dismissal on February 18, 2022.

- A putative class action lawsuit against Exelon and certain officers of Exelon and ComEd was filed in federal court in December 2019 alleging misrepresentations and omissions in Exelon’s SEC filings related to ComEd’s lobbying activities and the related investigations. The complaint was amended on September 16, 2020, to dismiss two of the original defendants and add other defendants, including ComEd. Defendants filed a motion to dismiss in November 2020. The court denied the motion in April 2021. On May 26, 2021, defendants moved the court to certify its order denying the motion to dismiss for interlocutory appeal. Briefing on the motion was completed in June 2021. That motion was denied on January 28, 2022. In May 2021, the parties each filed respective initial discovery disclosures. On June 9, 2021, defendants filed their answer and affirmative defenses to the complaint and the parties engaged thereafter in discovery. On September 9, 2021, the U.S. government moved to intervene in the lawsuit and stay discovery until the parties entered into an amendment to their protective order that would prohibit the parties from requesting discovery into certain matters, including communications with the U.S. government. The court ordered said amendment to the protective order on November 15, 2021 and discovery resumed. The parties are required to substantially complete discovery by February 15, 2022. On February 10, 2022, the court granted an extension of the amendment to the protective order, at the U.S. government's request, to May 15, 2022, and directed the parties to submit a proposed joint schedule for the additional case proceedings by May 13, 2022.

- Six shareholders have sent letters to the Exelon Board of Directors from 2020 through January 2022 demanding, among other things, that the Exelon Board of Directors investigate and address alleged breaches of fiduciary duties and other alleged violations by Exelon and ComEd officers and directors related to the conduct described in the DPA. In the first quarter of 2021, the Exelon Board of Directors appointed a Special Litigation Committee ("SLC") consisting of disinterested and independent parties to investigate and address these shareholders' allegations and make recommendations to the Exelon Board of Directors based on the outcome of the SLC's investigation. In July 2021, one of the demand letter shareholders filed a derivative action against current and former Exelon and ComEd officers and directors, and against Exelon, as nominal defendant, asserting the same claims made in its demand letter. On October 12, 2021, the parties to the derivative action filed an agreed motion to stay that litigation for 120 days in order to allow the SLC to continue its investigation, which the court granted. On January 31, 2022, the parties jointly moved the court to extend the stay an additional 120 days.

- Two separate shareholder requests seeking review of certain Exelon books and records were received in August 2021 and January 2022. Exelon has responded to the first request and the shareholder thereafter sent a formal shareholder demand to the Exelon Board as discussed above. Exelon is in the process of responding to the second request.

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.

The ICC continues to conduct an investigation into rate impacts of conduct admitted in the DPA initiated on August 12, 2021. On December 16, 2021 ComEd filed direct testimony addressing the costs recovered from customers related to the DPA and Exelon’s funding of the fine paid by ComEd. In that testimony, ComEd proposed to voluntarily refund to customers compensation costs of the former officers charged with wrongdoing in connection with events described in the DPA for the period during which those events occurred as well as costs, previously proposed to be returned, of individuals and entities specifically identified in the DPA, as well as individuals and entities who were referred to ComEd as part of the conduct described in the DPA and who failed, during their tenure at ComEd, to perform work to management expectations. Exelon and ComEd recorded a loss contingency for these compensation costs as of December 31, 2021, which for financial statement disclosure purposes is not material. The testimony supports the calculation of the refund amount and proposes a refund mechanism (one time bill credit in February 2023) and also addresses other topics outlined by statute and the ICC orders initiating the investigation. ComEd also presented evidence concerning the lawfulness of ComEd's past rates more generally. However, in response to pre-hearing motions concerning the scope of the hearing and permissible discovery and testimony, the ICC Administrate Law Judge ("ALJ") assigned ruled that scope of this proceeding was limited to whether ComEd used ratepayer funds to pay the "effectuation costs" for the conduct described in the DPA and to pay the criminal fine. Consistent with that scope, the ALJ limited the testimony to those subjects. Consistent with that ruling and a failure to exhaust other discovery, on January 18, 2022 the ALJ denied plaintiffs' counsel's request to depose witnesses including several current and former ComEd and Exelon executives.

Impacts of the February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages (Exelon). Beginning on February 15, 2021, Exelon's Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced outages as a result of extreme cold weather conditions. In addition, those weather conditions drove increased demand for service, dramatically increased wholesale power prices, and also increased gas prices in certain regions. See Note 3 — Regulatory Matters for additional information.

Various lawsuits have been filed against Exelon since March 2021 related to these events, including:

- On March 5, 2021, Exelon, along with more than 160 power generators and transmission and distribution companies, was sued by approximately 160 individually named plaintiffs, purportedly on behalf of all Texans who allegedly suffered loss of life or sustained personal injury, property damage or other losses as a result of the weather events. The plaintiffs allege that the defendants failed to properly prepare for the cold weather and failed to properly conduct their operations, seeking compensatory as well as punitive damages. On April 26, 2021, another multi-plaintiff lawsuit was filed on behalf of approximately 90 plaintiffs against more than 300 defendants, including Exelon, involving similar allegations of liability and claims of personal injury and property damage. Since March 2021, approximately 60 additional lawsuits, naming multiple defendants including Exelon, were filed by individual or multiple plaintiffs in different Texas counties, all arising out of the February weather events. These additional lawsuits allege wrongful death, property damage, or other losses. Co-defendants in these lawsuits include ERCOT, transmission and distribution utilities and other generators. On December 28, 2021, approximately 130 insurance companies which insured Texas homeowners and businesses filed a subrogation lawsuit against multiple defendants, including Exelon, alleging that defendants were at fault for the energy failure that resulted from the winter storm, causing significant property damage to the insureds. Additionally, as of January 28, 2022, Exelon has been added to approximately 80 additional wrongful death, personal injury and property damage lawsuits through the Multi-District-Litigation (MDL) pending in Texas state court. The MDL now includes all of the above-described Texas state court matters. Exelon disputes liability and denies that it is responsible for any of plaintiffs' alleged claims and is vigorously contesting them. No loss contingencies have been reflected in Exelon's consolidated financial statements with respect to these matters, as such contingencies are neither probable nor reasonably estimable at this time.

- On March 22, 2021, an LDC filed a lawsuit in Missouri federal court against Generation for breach of contract and unjust enrichment, seeking damages of approximately $40 million. The plaintiff claims that Generation failed to deliver gas to its customers in February of 2021, causing the plaintiff to incur damages by forcing it to purchase gas for Exelon's customers and by Exelon's refusal to pay the resulting penalties. On March 26, 2021, Exelon filed a complaint with the MPSC against the LDC to void the OFO penalties, or alternatively to grant a waiver or variance from the tariff requirements, to prohibit the LDC from billing or otherwise attempting to collect from Exelon or any Missouri customer any portion of the penalties claimed by the LDC until the resolution of the complaint, and to prohibit the LDC from taking any retaliatory measure, including termination of service. On September 1, 2021, the MPSC consolidated Exelon's complaint with two other similar complaints from other companies. On January 4, 2022, the court denied Exelon's motion to dismiss, but in the alternative granted its motion to stay pending MPSC resolution of Exelon's complaint. The MPSC has scheduled an evidentiary hearing for the three consolidated complaint cases in April 2022. Based on the penalty provisions within the tariff that was in effect at the relevant time, Exelon recorded a liability of approximately $40 million as of December 31, 2021.

Savings Plan Claim (Exelon). On December 6, 2021, seven current and former employees filed a putative ERISA class action suit in U.S. District Court for the Northern District of Illinois against Exelon, its Board of Directors, the former Board Investment Oversight Committee, the Corporate Investment Committee, individual defendants, and other unnamed fiduciaries of the Exelon Corporation Employee Savings Plan ("Plan"). The complaint alleges that the defendants violated their fiduciary duties under the Plan by including certain investment options that allegedly were more expensive than and underperformed similar passively-managed or other funds available in the marketplace and permitting a third-party administrative service provider/recordkeeper and an investment adviser to charge excessive fees for the services provided. The plaintiffs seek declaratory, equitable and monetary relief on behalf of the Plan and participants. On February 16, 2022, the court granted the parties' stipulated dismissal of the individual named defendants without prejudice. The remaining defendants' responsive pleading is due February 25, 2022. No loss contingencies have been reflected in Exelon's consolidated financial statements with respect to this matter, as such contingencies are neither probable nor reasonably estimable at this time.

General (All Registrants). The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The 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 (All 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,	
	2021	2020
Warrants outstanding	60,061	60,143
Common Stock reserved for conversion	20,020	20,048

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, 2021 and 2020. 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, 2021 and 2020.

The following table presents ComEd's, BGE's, and ACE's preference securities authorized, none of which were outstanding as of December 31, 2021 and 2020. 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, 2021 and 2020.

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, 2021, there were approximately 33 million shares authorized for issuance under the LTIP. For the years ended December 31, 2021, 2020, and 2019, 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 Consolidated Statements of Operations and Comprehensive Income. The Utility Registrants' stock-based compensation expense for the years ended December 31, 2021, 2020, and 2019 was not material.

	Year Ended December 31,		
Exelon	2021	2020	2019
Total stock-based compensation expense included in operating and maintenance expense	$ 142	$ 64	$ 77
Income tax benefit	(37)	(16)	(20)
Total after-tax stock-based compensation expense	$ 105	$ 48	$ 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,		
	2021	2020	2019
Performance share awards	$ 9	$ 21	$ 41
Restricted stock units	11	15	24

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, 2020[(a)]	930,392	$ 43.67
Granted	1,131,788	43.37
Change in performance	713,202	45.59
Vested	(327,551)	38.66
Forfeited	(157,552)	44.45
Undistributed vested awards[(b)]	(1,067,763)	44.58
Nonvested at December 31, 2021[(a)]	1,222,516	$ 44.96

(a) Excludes 1,934,238 and 1,414,661 of performance share awards issued to retirement-eligible employees as of December 31, 2021 and 2020, respectively, as they are fully vested.

(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2021.

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,		
	2021[(a)]	2020	2019
Weighted average grant date fair value (per share)	$ 43.37	$ 46.61	$ 47.37
Total fair value of performance shares vested	44	39	158
Total fair value of performance shares settled in cash	28	63	131

(a) As of December 31, 2021, $26 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, 2020[a]	1,114,130	$ 43.67
Granted	879,606	44.21
Vested	(397,526)	44.39
Forfeited	(57,646)	44.98
Undistributed vested awards[b]	(396,515)	43.66
Nonvested at December 31, 2021[a]	1,142,049	$ 43.52

(a) Excludes 609,934 and 748,165 of restricted stock units issued to retirement-eligible employees as of December 31, 2021 and 2020, respectively, as they are fully vested.

(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2021.

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,		
	2021[a]	2020	2019
Weighted average grant date fair value (per share)	$ 44.21	$ 46.33	$ 45.65
Total fair value of restricted stock units vested	34	54	92

(a) As of December 31, 2021, $22 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, 2021 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, 2020	1,265,410	$ 40.57	0.91	$ 3
Options exercised	(928,003)	39.45		11
Options expired	(310,400)	43.40		
Balance of shares outstanding at December 31, 2021	27,007	$ 46.47	0.15	$ —
Exercisable at December 31, 2021[a]	27,007	$ 46.47	0.15	$ —

(a) Includes stock options issued to retirement eligible employees.

The following table summarizes additional information regarding stock options exercised:

	Year Ended December 31,		
	2021	2020	2019
Intrinsic value[a]	$ 11	$ 5	$ 9
Cash received for exercise price	37	18	59

(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:

	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items [a]	Foreign Currency Items	AOCI of Investments Unconsolidated Affiliates [b]	Total
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)
OCI before reclassifications	(1)	432	—	—	431
Amounts reclassified from AOCI	—	219	—	—	219
Net current-period OCI	(1)	651	—	—	650
Balance at December 31, 2021	$ (6)	$ (2,721)	$ (23)	$ —	$ (2,750)

(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.

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,		
	2021	2020	2019
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	$ 4	$ 16	$ 23
Actuarial loss reclassified to periodic benefit cost	(76)	(66)	(52)
Pension and non-pension postretirement benefit plans valuation adjustment	(153)	122	100

23. Variable Interest Entities (Exelon, PHI, and ACE)

At December 31, 2021 and 2020, Exelon, 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, PHI, and ACE as of December 31, 2021 and 2020. The assets, except as noted in the footnotes to the table below, can only be used to settle obligations of the VIEs. The liabilities, except as noted in the footnotes to the table below, are such that creditors, or beneficiaries, do not have recourse to the general credit of Exelon, PHI, and ACE.

	December 31, 2021			December 31, 2020		
	Exelon	PHI	ACE	Exelon	PHI[(a)]	ACE
Cash and cash equivalents	$ 35	$ —	$ —	$ 98	$ —	$ —
Restricted cash and cash equivalents	48	—	—	47	3	3
Accounts receivable						
Customer	24	—	—	148	—	—
Other	6	—	—	36	—	—
Inventories, net						
Materials and supplies	14	—	—	244	—	—
Assets held for sale(b)	—	—	—	101	—	—
Other current assets	405	—	—	696	5	—
Total current assets	532	—	—	1,370	8	3
Property, plant and equipment, net	2,027	—	—	5,803	—	—
Nuclear decommissioning trust funds	—	—	—	3,007	—	—
Other noncurrent assets	215	—	—	301	10	10
Total noncurrent assets	2,242	—	—	9,111	10	10
Total assets(c)	$ 2,774	$ —	$ —	$10,481	$ 18	$ 13
Long-term debt due within one year	$ 70	$ —	$ —	$ 94	$ 26	$ 21
Accounts payable	10	—	—	81	—	—
Accrued expenses	21	—	—	70	—	—
Unamortized energy contract liabilities	—	—	—	4	—	—
Liabilities held for sale(b)	—	—	—	16	—	—
Other current liabilities	1	—	—	5	—	—
Total current liabilities	102	—	—	270	26	21
Long-term debt	822	—	—	889	—	—
Asset retirement obligations	151	—	—	2,318	—	—
Other noncurrent liabilities	3	—	—	129	—	—
Total noncurrent liabilities	976	—	—	3,336	—	—
Total liabilities(d)	$ 1,078	$ —	$ —	$ 3,606	$ 26	$ 21

(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 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 balances include unrestricted assets for current unamortized energy contract assets of $23 million and $22 million, disclosed within other current assets in the table above, non-current unamortized energy contract assets of $202 million and $249 million, disclosed within other noncurrent assets in the table above, Assets held for sale of $0 million and $9 million, and other unrestricted assets of $0 million and $1 million as of December 31, 2021 and 2020, respectively.

(d) Exelon's balances include liabilities with recourse of $1 million and $8 million as of December 31, 2021 and 2020, respectively.

As of December 31, 2021 and 2020, Exelon's consolidated VIEs associated with Generation included the following:

Consolidated VIE or VIE groups:	Reason entity is a VIE:	Reason Exelon is primary beneficiary:
CENG - A joint venture between Generation and EDF. Generation had a 50.01% equity ownership in CENG as of December 31, 2020 and acquired EDF's 49.99% equity interest on August 6, 2021 resulting in CENG no longer being classified as a consolidated VIE beginning in the third quarter of 2021. 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.
CRP - A collection of wind and solar project entities. Generation has a 51% equity ownership in CRP. 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 CRP. Generation has a noncontrolling interest.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	Generation conducts the operational activities.
Antelope Valley - A solar generating facility, which is 100% owned by Generation. Antelope Valley sells all of its output to PG&E through a PPA.	The PPA contract absorbs variability through a performance guarantee.	Generation conducts all activities.
Equity investment in distributed energy company - Generation has a 31% equity ownership. This distributed energy company has an interest in an unconsolidated VIE. (See Unconsolidated VIEs disclosure below). Exelon 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.

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. On August 6, 2021, Generation and EDF entered into a settlement agreement pursuant to which Generation purchased EDF's equity interest in CENG and resulted in CENG no longer being classified as a consolidated VIE beginning in the third quarter of 2021. 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 and will continue to do so post-separation, however, any calls on this guarantee would require Generation to reimburse Exelon under the terms of the Separation Agreement. See Note 19 — Commitments and Contingencies and Note 26 - Separation for more details.

- 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. Both the support agreement and guarantee terminated upon separation.

Prior to August 6, 2021, Generation and EDF shared in the $688 million of the contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance. Following the execution of the settlement agreement, EDF no longer shares in the obligation.

CRP - CRP is a collection of wind and solar project entities and some of these project entities are VIEs that are consolidated by CRP. While Generation or CRP owns 100% of the solar entities and 100% of the majority of the wind entities, it has been determined that the wholly owned solar and wind entities are VIEs because the entities' customers absorb price variability from the entities through fixed price power and/or REC purchase agreements. Additionally, for the wind entities that have minority interests, it has been determined that these entities are VIEs because the governance rights of some investors are not proportional to their financial rights. Generation is the primary beneficiary of these solar and wind entities that qualify as VIEs because Generation controls operations and direct all activities of the facilities. There is limited recourse to Generation related to certain solar and wind entities.

In 2017, Exelon's interests in CRP were contributed to and are pledged for the CR non-recourse debt project financing structure. Refer to Note 17 — Debt and Credit Agreements for additional information.

As of December 31, 2021 and 2020, Exelon's, PHI's and ACE's consolidated VIE consists of:

Consolidated VIEs:	**Reason entity is a VIE:**	**Reason ACE is the primary beneficiary:**
ACE Funding - A special purpose entity formed by ACE for the purpose of securitizing authorized portions of ACE's recoverable stranded costs through the issuance and sale of Transition Bonds. Proceeds from the sale of each series of Transition Bonds by ATF were transferred to ACE in exchange for the transfer by ACE to ATF of the right to collect a non-bypassable Transition Bond Charge from ACE customers pursuant to bondable stranded costs rate orders issued by the NJBPU in an amount sufficient to fund the principal and interest payments on Transition Bonds and related taxes, expenses, and fees. In the fourth quarter of 2021, the Transition bonds were fully redeemed and ACE remitted its final payment to ATF. Upon redemption of the bonds, ATF no longer meets the definition of a variable interest entity.	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 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 Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in Exelon's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominantly related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon for the deliveries associated with the current billing cycles under the commercial agreements.

As of December 31, 2021 and 2020, Exelon had significant unconsolidated variable interests in several VIEs for which Exelon 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 significant unconsolidated VIE entities:

	December 31, 2021			December 31, 2020		
	Commercial Agreement VIEs	Equity Investment VIEs	Total	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 772	$ 372	$ 1,144	$ 777	$ 401	$ 1,178
Total liabilities[(a)]	80	216	296	61	223	284
Exelon's ownership interest in VIE[(a)]	—	139	139	—	157	157
Other ownership interests in VIE[(a)]	692	17	709	716	21	737

(a) These items represent amounts in the unconsolidated VIE balance sheets, not in Exelon’s Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs. Exelon does not have any exposure to loss as they do not have a carrying amount in the equity investment VIEs as of December 31, 2021 and 2020.

As of December 31, 2021 and 2020, Exelon's unconsolidated VIEs consist of:

Unconsolidated VIE groups:	Reason entity is a VIE:	Reason Exelon 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). Exelon 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	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the year ended December 31, 2021								
Utility[(a)]	$ 873	$ 246	$ 139	$ 88	$ 301	$ 278	$ 22	$ 3
Property	633	39	18	176	131	88	40	3
Payroll	233	27	16	18	27	7	5	3
For the year ended December 31, 2020								
Utility[(a)]	$ 859	$ 238	$ 135	$ 87	$ 299	$ 275	$ 21	$ 3
Property	602	30	16	164	126	84	39	3
Payroll	235	27	16	17	25	7	5	3
For the year ended December 31, 2019								
Utility[(a)]	$ 881	$ 242	$ 132	$ 90	$ 304	$ 286	$ 18	$ —
Property	595	29	17	153	122	85	34	2
Payroll	232	27	15	17	24	7	4	2

(a) Exelon’s utility tax represents gross receipts tax related to Generation's 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	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the year ended December 31, 2021								
Decommissioning-related activities:								
Net realized income on NDT funds[(a)]								
Regulatory Agreement Units	$ 817	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-Regulatory Agreement Units	449	—	—	—	—	—	—	—
Net unrealized gains on NDT funds								
Regulatory Agreement Units	351	—	—	—	—	—	—	—
Non-Regulatory Agreement Units	209	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities[(b)]	(917)	—	—	—	—	—	—	—
Decommissioning-related activities	909	—	—	—	—	—	—	—
AFUDC—Equity	136	34	26	27	49	40	6	3
Non-service net periodic benefit cost	91	—	—	—	—	—	—	—
Net unrealized losses from equity investments[(c)]	(160)	—	—	—	—	—	—	—
For the year ended December 31, 2020								
Decommissioning-related activities:								
Net realized income on NDT funds[(a)]								
Regulatory Agreement Units	$ 185	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-Regulatory Agreement Units	160	—	—	—	—	—	—	—
Net unrealized gains on NDT funds								
Regulatory Agreement Units	724	—	—	—	—	—	—	—
Non-Regulatory Agreement Units	391	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities[(b)]	(729)	—	—	—	—	—	—	—
Decommissioning-related activities	731	—	—	—	—	—	—	—
AFUDC—Equity	104	29	17	22	36	28	4	4
Non-service net periodic benefit cost	53	—	—	—	—	—	—	—
Net unrealized gains from equity investments[(c)]	186	—	—	—	—	—	—	—
For the year ended December 31, 2019								
Decommissioning-related activities:								
Net realized income on NDT funds[(a)]								
Regulatory Agreement Units	$ 297	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-Regulatory Agreement Units	363	—	—	—	—	—	—	—
Net unrealized gains on NDT funds								
Regulatory Agreement Units	795	—	—	—	—	—	—	—
Non-Regulatory Agreement Units	411	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities[(b)]	(876)	—	—	—	—	—	—	—
Decommissioning-related activities	990	—	—	—	—	—	—	—
AFUDC—Equity	85	17	13	21	34	25	4	5
Non-service net periodic benefit cost	13	—	—	—	—	—	—	—

(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 except for decommissioning-related impacts that were not offset for the Byron units starting in the second quarter of 2021, including the elimination of income taxes related to all NDT fund activity for those units. With the September 15, 2021 reversal of the previous decision to retire Byron, Generation resumed contractual offset for Byron as of that date. See Note 10 — Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning and the contractual offset suspension for the Byron units.

(c) Net unrealized (losses) gains from equity investments that became publicly traded entities in the fourth quarter of 2020 and the first half of 2021.

Supplemental Cash Flow Information

The following tables provide additional information about material items recorded in the Registrants' Consolidated Statements of Cash Flows.

	Depreciation, amortization, and accretion							
	Exelon	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
For the year ended December 31, 2021								
Property, plant, and equipment[a]	$ 5,384	$ 970	$ 336	$ 439	$ 627	$ 274	$ 169	$ 155
Amortization of regulatory assets[a]	594	235	12	152	194	129	41	24
Amortization of intangible assets, net[a]	58	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities[b]	31	—	—	—	—	—	—	—
Nuclear fuel[c]	992	—	—	—	—	—	—	—
ARO accretion[d]	514	—	—	—	—	—	—	—
Total depreciation, amortization, and accretion	$ 7,573	$ 1,205	$ 348	$ 591	$ 821	$ 403	$ 210	$ 179
For the year ended December 31, 2020								
Property, plant, and equipment[a]	$ 4,364	$ 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	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities[b]	30	—	—	—	—	—	—	—
Nuclear fuel[c]	983	—	—	—	—	—	—	—
ARO accretion[d]	500	—	—	—	—	—	—	—
Total depreciation, amortization, and accretion	$ 6,527	$ 1,133	$ 347	$ 550	$ 782	$ 377	$ 191	$ 180
For the year ended December 31, 2019								
Property, plant, and equipment[a]	$ 3,665	$ 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	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities[b]	21	—	—	—	—	—	—	—
Nuclear fuel[c]	1,016	—	—	—	—	—	—	—
ARO accretion[d]	491	—	—	—	—	—	—	—
Total depreciation, amortization, and accretion	$ 5,780	$ 1,033	$ 333	$ 502	$ 754	$ 374	$ 184	$ 157

(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 Exelon’s Consolidated Statements of Operations and Comprehensive Income.

(c) Included in Purchased power and fuel expense in Exelon’s Consolidated Statements of Operations and Comprehensive Income.

(d) Included in Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income.

	Cash paid (refunded) during the year:							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the year ended December 31, 2021								
Interest (net of amount capitalized)	$ 1,505	$ 372	$ 152	$ 134	$ 255	$ 132	$ 59	$ 56
Income taxes (net of refunds)	281	(72)	(4)	(38)	—	12	(9)	2
For the year ended December 31, 2020								
Interest (net of amount capitalized)	$ 1,521	$ 371	$ 144	$ 125	$ 257	$ 129	$ 61	$ 57
Income taxes (net of refunds)	10	(61)	(37)	(57)	46	40	12	(3)
For the year ended December 31, 2019								
Interest (net of amount capitalized)	$ 1,470	$ 343	$ 129	$ 106	$ 255	$ 130	$ 59	$ 55
Income taxes (net of refunds)	265	(42)	82	17	29	7	19	(5)

	Other non-cash operating activities:							
	Exelon	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
For the year ended December 31, 2021								
Pension and non-pension postretirement benefit costs	$ 411	$ 129	$ 8	$ 61	$ 49	$ 6	$ 2	$ 11
Allowance for credit losses	160	47	39	17	24	9	5	10
Other decommissioning-related activity(a)	(946)	—	—	—	—	—	—	—
Energy-related options(b)	125	—	—	—	—	—	—	—
True-up adjustments to decoupling mechanisms and formula rates(c)	(171)	(42)	(26)	(12)	(91)	(53)	(14)	(24)
Severance costs	(57)	2	—	—	1	—	—	—
Long-term incentive plan	137	—	—	—	—	—	—	—
Amortization of operating ROU asset	183	1	—	29	28	6	8	4
AFUDC - Equity	(136)	(34)	(26)	(27)	(49)	(40)	(6)	(3)
For the year ended December 31, 2020								
Pension and non-pension postretirement benefit costs	$ 411	$ 114	$ 5	$ 62	$ 70	$ 15	$ 7	$ 14
Allowance for credit losses	150	32	42	15	43	24	16	2
Other decommissioning-related activity(a)	(659)	—	—	—	—	—	—	—
Energy-related options(b)	104	—	—	—	—	—	—	—
True-up adjustments to decoupling mechanisms and formula rates(c)	(6)	47	(16)	(16)	(21)	(40)	7	12
Severance costs	105	1	1	—	—	—	—	—
Provision for excess and obsolete inventory	131	2	1	—	—	—	—	—
Long-term incentive plan	56	—	—	—	—	—	—	—
Amortization of operating ROU asset	222	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	$ 96	$ 12	$ 61	$ 95	$ 25	$ 15	$ 16
Allowance for credit losses	120	33	31	8	17	7	4	5
Other decommissioning-related activity(a)	(506)	—	—	—	—	—	—	—
Energy-related options(b)	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	3	—	30	33	8	8	4
Change in environmental liabilities	23	—	—	—	23	23	—	—
AFUDC - Equity	(85)	(17)	(13)	(21)	(34)	(25)	(4)	(5)

(a) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units except for decommissioning-related impacts that were not offset for the Byron units starting in the second quarter of 2021, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income, and income taxes related to all NDT fund activity for these units. With the September 15, 2021 reversal of the previous decision to retire Byron, Generation resumed contractual offset for Byron as of that date. See Note 10 — Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning and for additional information on the contractual offset suspension for the Byron units.

(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, DPL, and ACE, reflects the change in regulatory assets and liabilities associated with their decoupling mechanisms and transmission formula rates. For PECO, reflects the change in regulatory assets and liabilities associated with its transmission formula rate. 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	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2021								
Cash and cash equivalents	$ 1,182	$ 131	$ 36	$ 51	$ 136	$ 34	$ 28	$ 29
Restricted cash and cash equivalents	393	210	8	4	77	34	43	—
Restricted cash included in other long-term assets	44	43	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	$ 1,619	$ 384	$ 44	$ 55	$ 213	$ 68	$ 71	$ 29
December 31, 2020								
Cash and cash equivalents	$ 663	$ 83	$ 19	$ 144	$ 111	$ 30	$ 15	$ 17
Restricted cash and cash equivalents	438	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	—	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	$ 1,166	$ 405	$ 26	$ 145	$ 160	$ 65	$ 15	$ 30
December 31, 2019								
Cash and cash equivalents	$ 587	$ 90	$ 21	$ 24	$ 131	$ 30	$ 13	$ 12
Restricted cash and cash equivalents	358	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	$ 403	$ 27	$ 25	$ 181	$ 63	$ 13	$ 28
December 31, 2018								
Cash and cash equivalents	$ 1,349	$ 135	$ 130	$ 7	$ 124	$ 16	$ 23	$ 7
Restricted cash and cash equivalents	247	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	$ 330	$ 135	$ 13	$ 186	$ 53	$ 24	$ 30

Supplemental Balance Sheet Information

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

	Investments							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2021								
Equity method investments:								
Other equity method investments	$ 77	$ 6	$ 7	$ —	$ —	$ —	$ —	$ —
Other investments:								
Employee benefit trusts and investments[a]	315	—	27	14	145	120	—	—
Equity investments without readily determinable fair values	44	—	—	—	—	—	—	—
Other available for sale debt security investments	7	—	—	—	—	—	—	—
Total investments	$ 443	$ 6	$ 34	$ 14	$ 145	$ 120	$ —	$ —
December 31, 2020								
Equity method investments:								
Other equity method investments	$ 81	$ 6	$ 8	$ —	$ —	$ —	$ —	$ —
Other investments:								
Employee benefit trusts and investments[a]	283	—	22	10	140	115	—	—
Equity investments without readily determinable fair values	73	—	—	—	—	—	—	—
Other available for sale debt security investments	3	—	—	—	—	—	—	—
Total investments	$ 440	$ 6	$ 30	$ 10	$ 140	$ 115	$ —	$ —

(a) The Registrants' debt and equity security investments are recorded at fair market value.

	Accrued expenses							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2021								
Compensation-related accruals[a]	$ 991	$ 155	$ 77	$ 78	$ 113	$ 35	$ 20	$ 17
Taxes accrued	495	94	14	53	96	88	9	11
Interest accrued	341	116	41	44	52	28	8	11
December 31, 2020								
Compensation-related accruals[a]	$ 1,069	$ 170	$ 73	$ 84	$ 109	$ 36	$ 18	$ 17
Taxes accrued	527	94	16	73	117	90	18	12
Interest accrued	331	109	37	46	51	26	7	12

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

25. Related Party Transactions (All Registrants)

Utility Registrants' expense with Generation

The Utility Registrants incur expenses from transactions with the Generation affiliate as described in the footnotes to the table below. Such expenses 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,		
	2021	2020	2019
ComEd[(a)]	$ 376	$ 330	$ 369
PECO[(b)]	196	190	158
BGE[(c)]	236	315	289
PHI	366	367	353
Pepco[(d)]	270	279	264
DPL[(e)]	79	75	70
ACE[(f)]	17	13	19

(a) ComEd has an ICC-approved RFP contract with Generation to provide a portion of ComEd's electric supply requirements. ComEd also purchases RECs and ZECs from Generation.

(b) PECO receives electric supply from Generation under contracts executed through PECO's competitive procurement process. In addition, PECO has a ten-year agreement with Generation to sell solar AECs.

(c) BGE receives a portion of its energy requirements from Generation under its MDPSC-approved market-based SOS and gas commodity programs.

(d) Pepco receives electric supply from Generation under contracts executed through Pepco's competitive procurement process approved by the MDPSC and DCPSC.

(e) DPL receives a portion of its energy requirements from Generation under its MDPSC and DEPSC approved market-based SOS commodity programs.

(f) ACE receives electric supply from Generation under contracts executed through ACE's competitive procurement process.

Service Company Costs for Corporate Support

The Registrants receive a variety of corporate support services from BSC. Pepco, DPL, and ACE also receive corporate support services from PHISCO. See Note 1 - Significant Accounting Policies for additional information regarding BSC and PHISCO.

The following table presents the service company costs allocated to the Registrants:

	Operating and maintenance from affiliates			Capitalized costs		
	For the years ended December 31,			For the years ended December 31,		
	2021	2020	2019	2021	2020	2019
Exelon						
BSC				$ 637	$ 585	$ 516
PHISCO				72	61	72
ComEd						
BSC	304	283	263	207	186	148
PECO						
BSC	169	150	149	81	76	88
BGE						
BSC	189	170	157	92	132	126
PHI						
BSC	168	152	139	128	149	88
PHISCO	—	—	—	72	61	72
Pepco						
BSC	96	85	85	50	55	38
PHISCO	114	120	124	31	27	33
DPL						
BSC	61	54	52	43	51	25
PHISCO	99	97	100	22	18	20
ACE						
BSC	53	45	42	33	40	19
PHISCO	86	87	90	19	16	19

Current Receivables from/Payables to affiliates

The following tables present Current receivables from affiliates and Current payables to affiliates:

December 31, 2021

	Receivables from affiliates:										
Payables to affiliates:	ComEd	PECO	BGE	Pepco	DPL	ACE	Generation	BSC	PHISCO	Other	Total
ComEd		$ —	$ —	$ —	$ —	$ —	$ 41	$ 71	$ —	$ 9	$ 121
PECO	—		—	—	—	—	30	36	—	4	70
BGE	—	—		—	—	—	4	41	—	3	48
PHI	—	1	—	—	—	1	—	5	—	9	16
Pepco	—	—	1		1	1	20	21	12	3	59
DPL	—	—	—	—		—	4	17	11	1	33
ACE	—	—	—	—	—		7	13	9	2	31
Generation	13	—	—	—	—	—		102	—	16	131
Other	3	—	—	—	—	—	11	—	—		14
Total	$ 16	$ 1	$ 1	$ —	$ 1	$ 2	$ 117	$ 306	$ 32	$ 47	$ 523

December 31, 2020

	Receivables from affiliates:										
Payables to affiliates:	ComEd	PECO	BGE	Pepco	DPL	ACE	Generation	BSC	PHISCO	Other	Total
ComEd		$ —	$ —	$ —	$ —	$ —	$ 28	$ 59	$ —	$ 9	$ 96
PECO	1		—	—	—	—	17	28	—	4	50
BGE	—	—		—	—	—	11	47	—	3	61
PHI	—	—	—	—	—	—	—	4	—	11	15
Pepco	2	—	1		—	—	13	25	14	—	55
DPL	1	—	—	—		—	3	21	10	1	36
ACE	—	—	—	—	—		6	15	9	1	31
Generation	13	—	—	—	—	—		72	—	22	107
Other	5	2	2	2	1	6	25	—	—		43
Total	$ 22	$ 2	$ 3	$ 2	$ 1	$ 6	$ 103	$ 271	$ 33	$ 51	$ 494

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. 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 affiliates

ComEd and PECO have Noncurrent receivables with Generation 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.

Long-term debt to financing trusts

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

	As of December 31,					
	2021			2020		
	Exelon	ComEd	PECO	Exelon	ComEd	PECO
ComEd Financing III	$ 206	$ 205	$ —	$ 206	$ 205	$ —
PECO Trust III	81	—	81	81	—	81
PECO Trust IV	103	—	103	103	—	103
Total	$ 390	$ 205	$ 184	$ 390	$ 205	$ 184

26. Separation (Exelon)

On February 21, 2021, Exelon's Board of Directors approved a plan to separate the Utility Registrants and Generation, creating two publicly traded companies ("the separation").

On February 25, 2021, Exelon filed applications with FERC, NYPSC, and NRC seeking approvals for the separation of Generation. On March 25, 2021, Exelon filed a request for a private letter ruling with the IRS to confirm the tax-free treatment of the separation, which was received on September 23, 2021. Exelon received approval from FERC on August 24, 2021, NRC on November 16, 2021, and NYPSC on December 16, 2021 for the separation.

The Form 10 registration statement was declared effective by the SEC on December 29, 2021.

Exelon completed the separation on February 1, 2022, through the distribution of 326,663,937 common stock shares of Constellation Energy Corporation, the new publicly traded company, to Exelon shareholders. Under the separation plan, Exelon shareholders retained their current shares of Exelon stock and received one share of Constellation Energy Corporation common stock for every three shares of Exelon common stock held on January 20, 2022, the record date for the distribution, in a transaction that is tax-free to Exelon and its shareholders for U.S. federal income tax purposes.

In order to govern the ongoing relationships between Exelon and Constellation Energy Corporation after the separation, and to facilitate an orderly transition, Exelon and Constellation Energy Corporation have entered into several agreements, including a Separation Agreement, Tax Matters Agreement, a Transition Services Agreement, and an Employee Matters Agreement, and other ancillary agreements.

Pursuant to the Separation Agreement, Exelon made a cash payment of $1.75 billion to Generation on January 31, 2022. Exelon issued term loans of $2.0 billion on January 21, 2022 and January 24, 2022 primarily to fund the cash payment to Constellation Energy Corporation and for general corporate purposes. See Note 17 — Debt and Credit Agreements for additional information.

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 2021, each of the Registrant’s management, including its principal executive officer and principal financial officer, evaluated 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, 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, 2021, the principal executive officer and principal financial officer of each of the Registrants concluded that such Registrant’s disclosure controls and procedures were effective to accomplish 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 2021 that have materially affected, or are reasonably likely to materially affect, any of the Registrant's internal control over financial reporting. 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, 2021. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2021 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

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not Applicable

PART III

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 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 25, 2022.

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 2022 proxy statement (2022 Exelon Proxy Statement) and the ComEd information statement (2022 ComEd Information Statement) to be filed with the SEC on or before April 30, 2022 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 2022 Annual Meeting of Shareholders or the ComEd 2022 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 2022 Exelon Proxy Statement or the ComEd 2022 Information Statement and incorporated herein by reference.

Securities Authorized for Issuance under Exelon Equity Compensation Plans

Plan Category	[A] Number of securities to be issued upon exercise of outstanding Options, warrants and rights (Note 1)		[B] Weighted-average price of outstanding Options, warrants and rights (Note 2)	[C] 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	5,343,357	$	0.22	48,184,437

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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 2019, 2020, and 2021, 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 3,110,870 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 1,555,435. The balance also includes 431,918 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 13,633,243 shares remaining available for issuance from the employee stock purchase plan and 4,556,610 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 2022 Annual Meeting of Shareholders or the ComEd 2022 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 2022 in the Exelon Proxy Statement for the 2022 Annual Meeting of Shareholders and the ComEd 2022 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 25, 2022 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2021, 2020, and 2019

Consolidated Statements of Cash Flows for the Years Ended December 31, 2021, 2020, and 2019

Consolidated Balance Sheets at December 31, 2021 and 2020

Consolidated Statements of Changes in Equity for the Years Ended December 31, 2021, 2020, and 2019

Notes to Consolidated Financial Statements

(ii) Financial Statement Schedules:

Schedule I—Condensed Financial Information of Parent (Exelon Corporate) at December 31, 2021 and 2020 and for the Years Ended December 31, 2021, 2020, and 2019

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2021, 2020, and 2019

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, 2021	2020	2019
Operating expenses			
Operating and maintenance	$ (9)	$ (2)	$ 33
Operating and maintenance from affiliates	38	10	9
Other	2	2	1
Total operating expenses	31	10	43
Operating loss	(31)	(10)	(43)
Other income and (deductions)			
Interest expense, net	(333)	(378)	(321)
Equity in earnings of investments	1,996	2,313	3,254
Interest income from affiliates, net	16	30	39
Other, net	—	15	14
Total other income	1,679	1,980	2,986
Income before income taxes	1,648	1,970	2,943
Income taxes	(58)	7	7
Net income	$ 1,706	$ 1,963	$ 2,936
Other comprehensive income (loss), net of income taxes			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic costs	$ (4)	$ (40)	$ (64)
Actuarial loss reclassified to periodic cost	223	190	148
Pension and non-pension postretirement benefit plan valuation adjustment	431	(357)	(289)
Unrealized (loss) gain on cash flow hedges	—	(1)	1
Other comprehensive income (loss)	650	(208)	(204)
Comprehensive income	$ 2,356	$ 1,755	$ 2,732

See the Notes to Financial Statements

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Statements of Cash Flows

	For the Years Ended December 31,		
(In millions)	2021	2020	2019
Net cash flows provided by operating activities	$ 3,629	$ 3,018	$ 1,948
Cash flows from investing activities			
Changes in Exelon intercompany money pool	381	(477)	95
Notes receivable from affiliates	—	550	—
Investment in affiliates	(2,231)	(1,969)	(1,071)
Other investing activities	1	—	—
Net cash flows used in investing activities	(1,849)	(1,896)	(976)
Cash flows from financing activities			
Changes in short-term borrowings	—	(136)	136
Proceeds from short-term borrowings with maturities greater than 90 days	500	—	—
Repayments on short-term borrowings with maturities greater than 90 days	(350)	—	—
Issuance of long-term debt	—	2,000	—
Retirement of long-term debt	(300)	(1,450)	—
Dividends paid on common stock	(1,497)	(1,492)	(1,408)
Proceeds from employee stock plans	80	45	112
Other financing activities	19	(27)	—
Net cash flows used in financing activities	(1,548)	(1,060)	(1,160)
Increase (Decrease) in cash, restricted cash, and cash equivalents	232	62	(188)
Cash, restricted cash, and cash equivalents at beginning of period	63	1	189
Cash, restricted cash, and cash equivalents at end of period	$ 295	$ 63	$ 1

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Balance Sheets

	December 31,	
(In millions)	**2021**	**2020**
ASSETS		
Current assets		
Cash and cash equivalents	$ 295	$ 63
Accounts receivable, net		
Other accounts receivable	318	354
Accounts receivable from affiliates	35	11
Notes receivable from affiliates	217	598
Regulatory assets	266	315
Other	6	4
Total current assets	1,137	1,345
Property, plant, and equipment, net	45	46
Deferred debits and other assets		
Regulatory assets	3,164	3,816
Investments in affiliates	44,495	43,149
Deferred income taxes	1,513	1,625
Notes receivable from affiliates	319	324
Other	42	312
Total deferred debits and other assets	49,533	49,226
Total assets	$ 50,715	$ 50,617

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Balance Sheets

	December 31,	
(In millions)	2021	2020
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 650	$ 500
Long-term debt due within one year	1,150	300
Accounts payable	—	1
Accrued expenses	79	76
Payables to affiliates	360	457
Regulatory liabilities	3	4
Pension obligations	75	92
Other	7	4
Total current liabilities	2,324	1,434
Long-term debt	6,265	7,418
Deferred credits and other liabilities		
Regulatory liabilities	63	32
Pension obligations	7,038	8,351
Non-pension postretirement benefit obligations	116	387
Deferred income taxes	404	348
Other	112	62
Total deferred credits and other liabilities	7,733	9,180
Total liabilities	16,322	18,032
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 979 shares and 976 shares outstanding as of December 31, 2021 and 2020,	20,324	19,373
Treasury stock, at cost (2 shares as of December 31, 2021 and 2020)	(123)	(123)
Retained earnings	16,942	16,735
Accumulated other comprehensive loss, net	(2,750)	(3,400)
Total shareholders' equity	34,393	32,585
Total liabilities and shareholders' equity	$ 50,715	$ 50,617

See the Notes to Financial Statements

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.

As of December 31, 2021 and 2020, Exelon Corporate owned 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%. As a February 1, 2022, as a result of the completion of the separation, Exelon Corporate no longer owns any interest in Exelon Generation Company, LLC. See Note 26 — Separation of the Combined Notes to Consolidated Financial Statements for additional information.

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 as of December 31, 2021 and 2020.

Short-Term Loan Agreements

On March 23, 2017, Exelon Corporate entered into a term loan agreement for $500 million. The loan agreement was renewed on March 17, 2021 and will expire on March 16, 2022. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.65% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Short-term borrowings in Exelon's Consolidated Balance Sheet.

On March 24, 2021, Exelon Corporate entered into a 9-month term loan agreement for $200 million. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.65% and all indebtedness thereunder is unsecured. Exelon Corporate repaid the term loan on December 22, 2021.

On March 31, 2021, Exelon Corporate entered into a 9-month and 364-day term loan agreement for $150 million each with variable interest rates of LIBOR plus 0.65% and expiration dates of December 31, 2021 and March 30, 2022, respectively. The 364-day loan agreement is reflected in Short-term borrowings in Exelon's Consolidated Balance Sheet. Exelon Corporate repaid the 9-month term loan on December 29, 2021.

In connection with the separation, on January 24, 2022, Exelon Corporate entered into a 364-day term loan agreement for $1.15 billion. The loan agreement will expire on January 23, 2023. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to SOFR plus 0.75% and all indebtedness thereunder is unsecured.

Revolving Credit Agreements

As of December 31, 2021, Exelon Corporation had a $600 million aggregate bank commitment under its existing syndicated revolving facility in which $594 million was available to support additional commercial paper as of December 31, 2021. 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 February 1, 2022, Exelon Corporate entered into a new 5-year revolving credit facility with an aggregate bank commitment of $900 million at a variable interest rate of SOFR plus 1.275% which replaced its existing $600 million syndicated revolving credit facility.

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, 2021 and December 31, 2020:

	Rates		Maturity Date	December 31,	
				2021	2020
Long-term debt[a]					
Junior subordinated notes		3.50 %	2022	$ 1,150	$ 1,150
Senior unsecured notes[b]	3.40 % -	7.60 %	2025 - 2050	6,139	6,439
Total long-term debt				7,289	7,589
Unamortized debt discount and premium, net				(10)	(10)
Unamortized debt issuance costs				(39)	(47)
Fair value adjustment				175	186
Long-term debt due within one year				(1,150)	(300)
Long-term debt				$ 6,265	$ 7,418

(a) In connection with the separation, Exelon Corporate entered into three 18-month term loan agreements. On January 21, 2022, two of the loan agreements were issued for $300 million each with an expiration date of July 21, 2023. On January 24, 2022, the third loan agreement was issued for $250 million with an expiration date of July 24, 2023. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to SOFR plus 0.65%.

(b) Senior unsecured notes include mirror debt that is held on Exelon Corporation's balance sheet. In connection with the separation, on January 31, 2022, Exelon Corporate received cash from Generation of $258 million to settle the intercompany loan. See Note 17 — Debt and Credit Agreements for additional information on the merger debt.

The debt maturities for Exelon Corporate for the periods 2022, 2023, 2024, 2025, 2026, and thereafter are as follows:

2022	$ 1,150
2023	—
2024	—
2025	807
2026	750
Thereafter	4,582
Total long-term debt	$ 7,289

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.

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)	2021	2020	2019
Operating and maintenance from affiliates:			
BSC[(a)]	$ 38	$ 10	$ 9
Total operating and maintenance from affiliates:	$ 38	$ 10	$ 9
Interest income from affiliates, net:			
Generation	$ 16	$ 29	$ 36
BSC	—	1	3
Total interest income from affiliates, net:	$ 16	$ 30	$ 39
Equity in earnings (losses) of investments:			
EEDC[(b)]	$ 2,215	$ 1,729	$ 2,054
Generation	(206)	589	1,125
UII	—	—	97
PCI	(1)	—	1
Exelon Enterprises	—	—	(16)
Exelon INQB8R	(13)	(6)	(8)
Exelon Transmission Company	—	—	(2)
Other	1	1	3
Total equity in earnings of investments:	$ 1,996	$ 2,313	$ 3,254
Cash contributions received from affiliates	$ 3,674	$ 3,372	$ 2,514

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

(in millions)	As of December 31, 2021	2020
Accounts receivable from affiliates (current):		
BSC[a]	$ 4	$ —
Generation	13	3
ComEd	5	—
PECO	4	1
BGE	2	—
PHISCO	6	6
Exelon Enterprises	1	1
Total accounts receivable from affiliates (current):	$ 35	$ 11
Notes receivable from affiliates (current):		
BSC[a]	$ 210	$ 252
Generation(c)	—	285
PECO	—	40
PHI	7	21
Total notes receivable from affiliates (current):	$ 217	$ 598
Investments in affiliates:		
BSC[a]	$ 195	$ 196
EEDC[b]	32,621	30,103
Generation	11,219	12,400
PCI	62	62
UII	365	365
Voluntary Employee Beneficiary Association trust	3	—
Exelon Enterprises	3	3
Exelon INQB8R, LLC	29	23
Other	(2)	(3)
Total investments in affiliates:	$ 44,495	$ 43,149
Notes receivable from affiliates (non-current):		
Generation(c)	$ 319	$ 324
Accounts payable to affiliates (current):		
UII	$ 360	$ 360
BSC	—	91
EEDC[b]	—	4
Generation(c)	—	2
Total accounts payable to affiliates (current):	$ 360	$ 457

(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) entered into intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes receivable at Exelon Corporate from Generation. In connection with the separation, on January 31, 2022, Exelon Corporate received cash from Generation of $258 million to settle the intercompany loan. See Schedule 1 - 2. Debit and Credit agreements for additional information on the merger debt.

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, 2021					
Allowance for credit losses[a]	$ 437	$ 141 [b]	$ —	$ 127 [c]	$ 451
Deferred tax valuation allowance	27	—	32 [d]	—	59
Reserve for obsolete materials	276	(1)	(2)	10	263
For the year ended December 31, 2020					
Allowance for credit losses[a]	$ 294	$ 240 [b]	$ (18) [e]	$ 79 [c]	$ 437
Deferred tax valuation allowance	26	—	1	—	27
Reserve for obsolete materials	155	128 [f]	(1)	6	276
For the year ended December 31, 2019					
Allowance for credit losses[a]	$ 319	$ 119 [b]	$ 26	$ 170 [c]	$ 294
Deferred tax valuation allowance	35	—	(9)	—	26
Reserve for obsolete materials	156	6	—	7	155

(a) Excludes the non-current allowance for credit losses related to PECO's installment plan receivables of $14 million, $5 million, and $9 million for the years ended December 31, 2021, 2020, and 2019, 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) Primarily reflects write-offs, net of recoveries of individual accounts receivable.

(d) DPL recorded a full valuation allowance against Delaware net operating losses carryforwards due to a change in Delaware tax law. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information on the valuation allowance.

(e) 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.

(f) 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.

Commonwealth Edison Company and Subsidiary Companies

(2) ComEd

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 25, 2022 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2021, 2020, and 2019

Consolidated Statements of Cash Flows for the Years Ended December 31, 2021, 2020, and 2019

Consolidated Balance Sheets at December 31, 2021 and 2020

Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2021, 2020, and 2019

Notes to Consolidated Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2021, 2020, and 2019

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, 2021					
Allowance for credit losses	$ 118	$ 18 (a)	$ 1	$ 47 (b)	$ 90
Reserve for obsolete materials	6	3	—	2	7
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

(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

(3) PECO

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 25, 2022 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2021, 2020, and 2019

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Consolidated Balance Sheets at December 31, 2021 and 2020

Consolidated Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2021, 2020, and 2019

Notes to Consolidated Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2021, 2020, and 2019

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, 2021					
Allowance for credit losses[a]	$ 124	$ 32 [b]	$ (6)	$ 38 [c]	$ 112
Deferred tax valuation allowance	1	—	2	—	$ 3
Reserve for obsolete materials	2	1	—	1	2
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

(a) Excludes the non-current allowance for credit losses related to PECO's installment plan receivables of $14 million, $5 million, and $9 million for the years ended December 31, 2021, 2020, and 2019, 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

(4) BGE

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 25, 2022 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Statements of Operations and Comprehensive Income for the Years Ended December 31, 2021, 2020 and 2019

Statements of Cash Flows for the Years Ended December 31, 2021, 2020 and 2019

Balance Sheets at December 31, 2021 and 2020

Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2021, 2020 and 2019

Notes to Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2021, 2020, and 2019

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, 2021					
Allowance for credit losses	$ 44	$ 16 [(a)]	$ 3	$ 16 [(b)]	$ 47
Reserve for obsolete materials	1	—	—	—	1
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

(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

(5) PHI

(i) Financial Statements (Item 8):

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Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2021, 2020, and 2019

Consolidated Statements of Cash Flows for the Years Ended December 31, 2021, 2020, and 2019

Consolidated Balance Sheets at December 31, 2021 and 2020

Consolidated Statements of Changes in Equity for the Years Ended December 31, 2021, 2020, and 2019

Notes to Consolidated Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2021, 2020, and 2019

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, 2021					
Allowance for credit losses	$ 119	$ 41 [a]	$ 2	$ 19 [b]	$ 143
Deferred tax valuation allowance	—	—	31 [c]	—	31
Reserve for obsolete materials	2	1	—	—	3
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 [d]	$ 53
Deferred tax valuation allowance	8	—	(8)	—	—
Reserve for obsolete materials	2	1	—	—	3

(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) DPL recorded a full valuation allowance against Delaware net operating losses carryforwards due to a change in Delaware tax law. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information on the valuation allowance.

(d) Write-offs of individual accounts receivable.

Potomac Electric Power Company

(6) Pepco

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 25, 2022 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Statements of Operations and Comprehensive Income for the Years Ended December 31, 2021, 2020 and 2019

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Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2021, 2020 and 2019

Notes to Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2021, 2020, and 2019

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, 2021					
Allowance for credit losses	$ 45	$ 14 [(a)]	$ 2	$ 8 [(b)]	$ 53
Reserve for obsolete materials	1	—	—	—	1
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

(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

(7) DPL

(i) Financial Statements (Item 8):

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Statements of Operations and Comprehensive Income for the Years Ended December 31, 2021, 2020 and 2019

Statements of Cash Flows for the Years Ended December 31, 2021, 2020 and 2019

Balance Sheets at December 31, 2021 and 2020

Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2021, 2020 and 2019

Notes to Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2021, 2020, and 2019

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, 2021					
Allowance for credit losses	$ 31	$ 6 [(a)]	$ (1)	$ 10 [(b)]	$ 26
Deferred tax valuation allowance	—	—	31 [(c)]	—	31
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 [(d)]	$ 15

(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 DEPSC and MDPSC.

(b) Write-offs, net of recoveries of individual accounts receivable.

(c) DPL recorded a full valuation allowance against Delaware net operating losses carryforwards due to a change in Delaware tax law. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information on the valuation allowance.

(d) Write-off of individual accounts receivable.

Atlantic City Electric Company and Subsidiary Company

(8) ACE

(i) Financial Statements (Item 8):

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Consolidated Statements of Cash Flows for the Years Ended December 31, 2021, 2020, and 2019

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Consolidated Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2021, 2020, and 2019

Notes to Consolidated Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2021, 2020, and 2019

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, 2021					
Allowance for credit losses	$ 43	$ 21 [a]	$ 1	$ 1 [b]	$ 64
Reserve for obsolete materials	—	1	—	—	1
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

(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	Separation Agreement, dated January 31, 2022, between Exelon Corporation and Constellation Energy Corporation (File No. 001-16169, Form 8K dated February 2, 2022, 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	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).
3-4	Commonwealth Edison Company Amended and Restated By-Laws, Effective February 22, 2021 (File 001-01839, Form 10-K dated February 24, 2021, Exhibit 3.6).
3-5	Amended and Restated Articles of Incorporation of PECO Energy Company (File No. 001-01401, Form 10-K dated April 2, 2001, Exhibit 3.3).
3-6	PECO Energy Company Amended and Restated Bylaws dated August 3, 2020 (File 000-16844, Form 10-Q dated August 4, 2020, Exhibit 3.3).
3-7	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).
3-8	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).
3-9	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).
3-10	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).
3-11	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).
3-12	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).
3-13	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).
3-14	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).
3-15	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).

Exhibit No.	Description
3-16	Bylaws of Potomac Electric Power Company (File No. 001-01072, Form 10-Q dated May 5, 2006, Exhibit 3.2).
3-17	Bylaws of Delmarva Power & Light Company (File No. 001-01405, Form 10-Q dated May 9, 2005, Exhibit 3.2.1).
3-18	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 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, 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
February 15, 2021	000-16844, Form 8-K dated March 8, 2021	4.1
September 1, 2021	000-16844, Form 8-K, dated September 14, 2021	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
March 1, 2007	001-01839, Form 8-K dated March 23, 2007	4.1
December 20, 2007	001-01839, Form 8-K dated January 16, 2008	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
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 25, 2020	4.1
February 16, 2021	001-01839, Form 8-K dated March 9, 2021	4.1
August 2, 2021	001-01839, Form 8-K dated August 12, 2021	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 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).
4-8	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).
4-9	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).
4-10	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).
4-11	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).
4-12	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).
4-13	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)).
4-14	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).
4-14-1	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).
4-14-2	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).
4-15	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).
4-15-1	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).

Exhibit No.	Description
4-15-2	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).
4-15-3	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).
4-15-4	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).
4-16	Form of Conversion Supplemental Indenture, dated March 23, 2016 (File No. 001-31403, Form 8-K dated March 24, 2016, Exhibit 4.1).
4-17	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)
4-17-1	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
February 15, 2021	001-01072, Form 8-K dated March 30, 2021	4.2

Exhibit No.	Description
4-18	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)]
4-18-1	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
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
June 1, 2018	000-01405, Form 8-K dated June 21, 2018	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
February 15, 2021	001-01405, Form 8-K dated March 30, 2021	4.4
February 15, 2022	001-01405, Form 8-K dated February 15, 2022	4.4

Exhibit No.	Description
4-19	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)
4-19-1	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
February 15, 2021	001-03559, Form 8-K dated March 10, 2021	4.1
November 1, 2021	001-03559, Form 8-K dated November 16, 2021	4.2
February 15, 2022	001-03559, Form 8-K dated February 15, 2022	4.2

Exhibit No.	Description
4-20	Form of 2.400% notes due 2026 (File No. 001-01910, Form 8-K dated August 18, 2016, Exhibit 4.1).
4-21	Form of 3.500% notes due 2046 (File No. 001-01910, Form 8-K dated August 18, 2016, Exhibit 4.2).
4-22	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).
4-23	Form of Pepco First Mortgage Bond, 4.15% Series due March 15, 2043 (File No. 001-01072, Form 8-K dated May 22, 2017, Exhibit 4.2).

Exhibit No.	Description
4-24	Form of 3.750% BGE notes due 2047 (File No. 001-01910, Form 8-K dated August 24, 2017, Exhibit 4.1).
4-25	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).
4-26	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).
4-27	Description of Exelon Securities (File No. 001-16169, Form 10-K dated February 11, 2020, Exhibit 4.63).
4-28	Description of PECO Securities (File No. 001-16169, Form 10-K dated February 11, 2020, Exhibit 4.64).
4-29	Description of ComEd Securities (File No. 001-16169, Form 10-K dated February 11, 2020, Exhibit 4.65).
4-30	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).
4-31	Gas Facilities Loan Agreement, dated as of July 1, 2020, between The Delaware Economic Development Authority and Delmarva Power & Light Company (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).

Exhibit No.	Description
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).
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	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).

Exhibit No.	Description
10-24	2016 Form of Exelon Corporation Change in Control Agreement (File No. 001-16169, Form 10-Q dated October 26, 2016, Exhibit 10.1).
10-25	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).

Exhibit No.	Description
10-26	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).
10-27	Exelon Corporation 2020 Long-Term Incentive Plan (Effective April 28, 2020) (File No. 001-16169, Proxy Statement dated March 18, 2020, Appendix A).
10-28	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).
10-29	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).
10-30	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).
10-31	Letter Agreement, dated June 4, 2020, between Exelon Corporation and William A. Von Hoene, Jr. (File 001-16169, Form 10-K dated February 24, 2021, Exhibit 10.74)
10-32	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).
10-33	Transition Services Agreement, dated January 31, 2022, between Exelon Corporation and Constellation Energy Corporation (File No. 001-16169, Form 8K dated February 2, 2022, Exhibit 10.1)
10-34	Tax Matters Agreement, dated January 31, 2022, between Exelon Corporation and Constellation Energy Corporation (File No. 001-16169, Form 8K dated February 2, 2022, Exhibit 10.2)
10-35	Employee Matters Agreement, dated January 31, 2022, between Exelon Corporation and Constellation Energy Corporation (File No. 001-16169, Form 8K dated February 2, 2022, Exhibit 10.3)
10-36	Credit Agreement for $300,000,000 dated January 21, 2022, between Exelon Corporation, various financial institutions, and Sumitomo Mitsui Banking Corp**
10-37	Credit Agreement for $300,000,000 dated January 21, 2022, between Exelon Corporation, various financial institutions, and U.S. Bank**
10-38	Credit Agreement for $1,150,000,000 dated January 24, 2022, between Exelon Corporation and Barclays Bank PLC**
10-39	Credit Agreement for $250,000,000 dated January 24, 2022, between Exelon Corporation, various financial institutions and PNC Bank**
10-40	Credit Agreement for $900,000,000 dated February 1, 2022, between Exelon Corporation and various financial institutions**
10-41	Credit Agreement for $600,000,000 dated February 1, 2022, between Baltimore Gas and Electric Company and various financial institutions**
10-42	Credit Agreement for $1,000,000,000 dated February 1, 2022, between Commonwealth Edison Company and various financial institutions**
10-43	Credit Agreement for $600,000,000 dated February 1, 2022, between PECO Energy Company and various financial institutions**
10-44	Credit Agreement for $900,000,000 dated February 1, 2022, between Potomac Electric Power Company, Delmarva Power & Light Company, Atlantic City Electric Company and various financial institutions**

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	Commonwealth Edison Company
21-3	PECO Energy Company
21-4	Baltimore Gas and Electric Company
21-5	Pepco Holdings LLC
21-6	Potomac Electric Power Company
21-7	Delmarva Power & Light Company
21-8	Atlantic City Electric Company
	Consent of Independent Registered Public Accountants
23-1	Exelon Corporation
23-2	Commonwealth Edison Company
23-3	PECO Energy Company
23-4	Baltimore Gas and Electric Company
23-5	Potomac Electric Power Company
23-6	Delmarva Power & Light Company
23-7	Atlantic City Electric Company
	Power of Attorney (Exelon Corporation)
24-1	Anthony K. Anderson
24-2	Ann C. Berzin
24-3	W. Paul Bowers
24-4	Marjorie Rodgers Cheshire
24-5	Christopher M. Crane
24-6	Carlos Gutierrez
24-7	Linda P. Jojo
24-8	Paul Joskow
24-9	Mayo A. Shattuck III
24-10	John F. Young
	Power of Attorney (Commonwealth Edison Company)
24-11	Calvin G. Butler, Jr.
24-12	Christopher M. Crane
24-13	Nicholas DeBenedictis
24-14	Ricardo Estrada

Exhibit No.	Description
24-15	Zaldwaynaka Scott
24-16	Smita Shah
24-17	Gil C. Quiniones
	Power of Attorney (PECO Energy Company)
24-18	Calvin G. Butler, Jr.
24-19	Christopher M. Crane
24-20	Nicholas DeBenedictis
24-21	Nelson A. Diaz
24-22	John S. Grady
24-23	Rosemarie B. Greco
24-24	Michael A. Innocenzo
24-25	Charisse R. Lillie
	Power of Attorney (Baltimore Gas and Electric Company)
24-26	Ann C. Berzin
24-27	Calvin G. Butler, Jr.
24-28	Christopher M. Crane
24-29	Michael E. Cryor
24-30	James R. Curtiss
24-31	Joseph Haskins, Jr.
24-32	Carim V. Khouzami
24-33	Amy Seto
24-34	Maria Harris Tildon
	Power of Attorney (Pepco Holdings LLC)
24-35	Antoine Allen
24-36	J. Tyler Anthony
24-37	Calvin G. Butler, Jr.
24-38	Christopher M. Crane
24-39	Linda W. Cropp
24-40	Michael E. Cryor
24-41	Debra P. DiLorenzo
	Power of Attorney (Potomac Electric Power Company)
24-42	J. Tyler Anthony
24-43	Phillip S. Barnett
24-44	Calvin G. Butler, Jr.

Exhibit No.	Description
24-45	Christopher M. Crane
24-46	Rodney Oddoye
24-47	Elizabeth O'Donnell
24-48	Tamla Olivier
	Power of Attorney (Delmarva Power & Light Company)
24-49	J. Tyler Anthony
24-50	Calvin G. Butler, Jr.
	Power of Attorney (Atlantic City Electric Company)
24-51	J. Tyler Anthony

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, 2021 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 Gil C. Quiniones for Commonwealth Edison Company
31-4	Filed by Joseph R. Trpik for Commonwealth Edison Company
31-5	Filed by Michael A. Innocenzo for PECO Energy Company
31-6	Filed by Robert J. Stefani for PECO Energy Company
31-7	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
31-8	Filed by David M. Vahos for Baltimore Gas and Electric Company
31-9	Filed by J. Tyler Anthony for Pepco Holdings LLC
31-10	Filed by Phillip S. Barnett for Pepco Holdings LLC
31-11	Filed by J. Tyler Anthony for Potomac Electric Power Company
31-12	Filed by Phillip S. Barnett for Potomac Electric Power Company
31-13	Filed by J. Tyler Anthony for Delmarva Power & Light Company
31-14	Filed by Phillip S. Barnett for Delmarva Power & Light Company
31-15	Filed by J. Tyler Anthony for Atlantic City Electric Company
31-16	Filed by Phillip S. Barnett for Atlantic City Electric Company

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code as to the Annual Report on Form 10-K for the year ended December 31, 2021 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 Gil C. Quiniones for Commonwealth Edison Company
32-4	Filed by Joseph R. Trpik for Commonwealth Edison Company

Exhibit No.	Description
32-5	Filed by Michael A. Innocenzo for PECO Energy Company
32-6	Filed by Robert J. Stefani for PECO Energy Company
32-7	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
32-8	Filed by David M. Vahos for Baltimore Gas and Electric Company
32-9	Filed by J. Tyler Anthony for Pepco Holdings LLC
32-10	Filed by Phillip S. Barnett for Pepco Holdings LLC
32-11	Filed by J. Tyler Anthony for Potomac Electric Power Company
32-12	Filed by Phillip S. Barnett for Potomac Electric Power Company
32-13	Filed by J.Tyler Anthony for Delmarva Power & Light Company
32-14	Filed by Phillip S. Barnett for Delmarva Power & Light Company
32-15	Filed by J. Tyler Anthony for Atlantic City Electric Company
32-16	Filed by Phillip S. Barnett for Atlantic City Electric Company
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	Inline XBRL Taxonomy Extension Schema Document.
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	Inline XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

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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 25th day of February, 2022.

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 25th day of February, 2022.

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
W. Paul Bowers
Marjorie Rodgers Cheshire
Carlos Gutierrez
Linda P. Jojo
Paul Joskow
Mayo A. Shattuck III
John F. Young

By: /s/ GAYLE E. LITTLETON February 25, 2022
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 25th day of February, 2022.

COMMONWEALTH EDISON COMPANY

By: /s/ GIL C. QUINIONES
Name: Gil C. Quiniones
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 25th day of February, 2022.

Signature	Title
/s/ GIL C. QUINIONES Gil C. Quiniones	Chief Executive Officer (Principal Executive Officer) and Director
/s/ JOSEPH R. TRPIK Joseph R. Trpik	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 Gil C. Quiniones, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Calvin G. Butler, Jr.
Christopher M. Crane
Nicholas DeBenedictis

Ricardo Estrada
Zaldwaynaka Scott
Smita Shah

By: /s/ GIL C. QUINIONES February 25, 2022
Name: Gil C. Quiniones

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 25th day of February, 2022.

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 25th day of February, 2022.

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, Jr.
Christopher M. Crane
Nicholas DeBenedictis
Nelson A. Diaz

John S. Grady
Rosemarie B. Greco
Charisse R. Lillie

By: /s/ MICHAEL A. INNOCENZO February 25, 2022
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 25th day of February, 2022.

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 25th day of February, 2022.

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, Jr.
Christopher M. Crane
Michael E. Cryor
James R. Curtiss
Joseph Haskins, Jr.
Amy Seto
Maria Harris Tildon

By: /s/ CARIM V. KHOUZAMI February 25, 2022
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 25th day of February, 2022.

PEPCO HOLDINGS LLC

By: /s/ J. TYLER ANTHONY
Name: J. Tyler Anthony
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 25th day of February, 2022.

Signature	**Title**
/s/ J. TYLER ANTHONY J. Tyler Anthony	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 J. Tyler Anthony, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Antoine Allen
Calvin G. Butler, Jr.
Christopher M. Crane

Linda W. Cropp
Michael E. Cryor
Debra P. DiLorenzo

By: /s/ J. TYLER ANTHONY February 25, 2022
Name: J. Tyler Anthony

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 25th day of February, 2022.

POTOMAC ELECTRIC POWER COMPANY

By: /s/ J. TYLER ANTHONY
Name: J. Tyler Anthony
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 25th day of February, 2022.

Signature	Title
/s/ J. TYLER ANTHONY J. Tyler Anthony	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 J. Tyler Anthony, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Phillip S. Barnett
Calvin G. Butler, Jr.
Christopher M. Crane

Rodney Oddoye
Elizabeth O'Donnell
Tamla Olivier

By: /s/ J. TYLER ANTHONY February 25, 2022
Name: J. Tyler Anthony

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 25th day of February, 2022.

DELMARVA POWER & LIGHT COMPANY

By: /s/ J. TYLER ANTHONY
Name: J. Tyler Anthony
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 25th day of February, 2022.

Signature	Title
/s/ J. TYLER ANTHONY J. Tyler Anthony	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 J. Tyler Anthony, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Calvin G. Butler, Jr.

By: /s/ J. TYLER ANTHONY February 25, 2022
Name: J. Tyler Anthony

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 25th day of February, 2022.

ATLANTIC CITY ELECTRIC COMPANY

By:	/s/ J. TYLER ANTHONY
Name:	J. Tyler Anthony
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 25th day of February, 2022.

Signature	**Title**
/s/ J. TYLER ANTHONY J. Tyler Anthony	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)