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

FORM 10-Q

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

For the Quarterly Period Ended September 30, 2020
or

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

Commission File Number	Name of Registrant; State or Other Jurisdiction of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
001-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
001-01839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
001-01910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210
001-31403	PEPCO HOLDINGS LLC (a Delaware limited liability company) 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	52-2297449
001-01072	POTOMAC ELECTRIC POWER COMPANY (a District of Columbia and Virginia corporation) 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	53-0127880
001-01405	DELMARVA POWER & LIGHT COMPANY (a Delaware and Virginia corporation) 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	51-0084283
001-03559	ATLANTIC CITY ELECTRIC COMPANY (a New Jersey corporation) 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	21-0398280

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
EXELON CORPORATION:		
Common Stock, without par value	EXC	The Nasdaq Stock Market LLC
PECO ENERGY COMPANY:		
Trust Receipts of PECO Energy Capital Trust III, each representing a 7.38% Cumulative Preferred Security, Series D, $25 stated value, issued by PECO Energy Capital, L.P. and unconditionally guaranteed by PECO Energy Company	EXC/28	New York Stock Exchange

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

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

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

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

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

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

The number of shares outstanding of each registrant's common stock as of September 30, 2020 was:

Exelon Corporation Common Stock, without par value	975,572,463
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,021,354
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000
Pepco Holdings LLC	not applicable
Potomac Electric Power Company Common Stock, $0.01 par value	100
Delmarva Power & Light Company Common Stock, $2.25 par value	1,000
Atlantic City Electric Company Common Stock, $3.00 par value	8,546,017

TABLE OF CONTENTS

GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

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

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

Note - of the 2019 Form 10-K	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2019 Annual Report on Form 10-K
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
BGS	Basic Generation Service
CBA	Collective Bargaining Agreement
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended
CES	Clean Energy Standard
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
CODM	Chief operating decision maker(s)
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
DC PLUG	District of Columbia Power Line Undergrounding Initiative
DCPSC	Public Service Commission of the District of Columbia
DOE	United States Department of Energy
DOEE	District of Columbia Department of Energy & Environment
DOJ	United States Department of Justice
DPP	Deferred Purchase Price
DPSC	Delaware Public Service Commission
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
FASB	Financial Accounting Standards Board
FEJA	Illinois Public Act 99-0906 or Future Energy Jobs Act
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FRR	Fixed Resource Requirement
GAAP	Generally Accepted Accounting Principles in the United States
GCR	Gas Cost Rate
GSA	Generation Supply Adjustment
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
ISO	Independent System Operator
ISO-NE	Independent System Operator New England Inc.
LIBOR	London Interbank Offered Rate
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
MW	Megawatt
MWh	Megawatt hour
NDT	Nuclear Decommissioning Trust
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
NPNS	Normal Purchase Normal Sale scope exception
NRC	Nuclear Regulatory Commission
NYISO	New York Independent System Operator Inc.
NYMEX	New York Mercantile Exchange
NYPSC	New York Public Service Commission
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PAPUC	Pennsylvania Public Utility Commission
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
PPE	Property, plant, and equipment
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
PSDAR	Post-Shutdown Decommissioning Activities Report
PSEG	Public Service Enterprise Group Incorporated
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
RNF	Revenues Net of Purchased Power and Fuel Expense
Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RMC	Risk Management Committee
ROE	Return on equity

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
ROU	Right-of-use
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Services
SEC	United States Securities and Exchange Commission
SEIU	Service Employees International Union
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPFPA	International Union, Security, Police, and Fire Professionals of America
STRIDE	Maryland Strategic Infrastructure Development and Enhancement Program
TCJA	Tax Cuts and Jobs Act
Transition Bonds	Transition Bonds issued by ACE Funding
UGSOA	United Government Security Officers of America
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council
ZEC	Zero Emission Credit, or Zero Emission Certificate
ZES	Zero Emission Standard

FILING FORMAT

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

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING INFORMATION

This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties including among others those related to the expected or potential impact of the novel coronavirus (COVID-19) pandemic, and the related responses of various governments and regulatory bodies, our customers, and the company, on our business, financial condition and results of operations; any such forward-looking statements, whether concerning the COVID-19 pandemic or otherwise, involve risks, assumptions and uncertainties. Words such as “could,” “may,” “expects,” “anticipates,” “will,” “targets,” “goals,” “projects,” “intends,” “plans,” “believes,” “seeks,” “estimates,” “predicts,” and variations on such words, and similar expressions that reflect our current views with respect to future events and operational, economic and financial performance, are intended to identify such forward-looking statements.

The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, as well as the items discussed in (1) the Registrants' combined 2019 Annual Report on Form 10-K in (a) Part I, ITEM 1A. Risk Factors, (b) Part II, ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, and (c) Part II, ITEM 8. Financial Statements and Supplementary Data: Note 18, Commitments and Contingencies; (2) this Quarterly Report on Form 10-Q in (a) Part II, ITEM 1A. Risk Factors, (b) Part I, ITEM 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations, and (c) Part I, ITEM 1. Financial Statements: Note 14, Commitments and Contingencies; and (3) other factors discussed in filings with the SEC by the Registrants.

Investors are cautioned not to place undue reliance on these forward-looking statements, whether written or oral, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

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

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

(In millions, except per share data)	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Operating revenues				
Competitive businesses revenues	$ 4,330	$ 4,499	$ 12,344	$ 13,436
Rate-regulated utility revenues	4,533	4,510	12,643	12,758
Revenues from alternative revenue programs	(11)	(80)	(66)	(98)
Operating revenue from affiliates	1	—	4	—
Total operating revenues	8,853	8,929	24,925	26,096
Operating expenses				
Competitive businesses purchased power and fuel	2,311	2,648	6,967	8,142
Rate-regulated utility purchased power and fuel	1,303	1,304	3,439	3,589
Operating and maintenance	2,732	2,072	7,370	6,419
Depreciation and amortization	1,289	1,083	3,312	3,237
Taxes other than income taxes	452	452	1,299	1,316
Total operating expenses	8,087	7,559	22,387	22,703
Gain (Loss) on sales of assets and businesses	3	(17)	16	19
Operating income	769	1,353	2,554	3,412
Other income and (deductions)				
Interest expense, net	(398)	(403)	(1,222)	(1,202)
Interest expense to affiliates	(6)	(6)	(19)	(19)
Other, net	421	158	352	837
Total other income and (deductions)	17	(251)	(889)	(384)
Income before income taxes	786	1,102	1,665	3,028
Income taxes	216	172	141	626
Equity in losses of unconsolidated affiliates	(1)	(170)	(5)	(182)
Net income	569	760	1,519	2,220
Net income (loss) attributable to noncontrolling interests	68	(12)	(85)	56
Net income attributable to common shareholders	$ 501	$ 772	$ 1,604	$ 2,164
Comprehensive income, net of income taxes				
Net income	$ 569	$ 760	$ 1,519	$ 2,220
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(10)	(16)	(30)	(49)
Actuarial loss reclassified to periodic benefit cost	49	37	142	111
Pension and non-pension postretirement benefit plan valuation adjustment	(13)	6	(17)	(32)
Unrealized loss on cash flow hedges	(1)	—	(2)	—
Unrealized gain on investments in unconsolidated affiliates	—	5	—	1
Unrealized gain (loss) on foreign currency translation	3	(2)	(3)	2
Other comprehensive income	28	30	90	33
Comprehensive income	597	790	1,609	2,253
Comprehensive income (loss) attributable to noncontrolling interests	68	(9)	(85)	57
Comprehensive income attributable to common shareholders	$ 529	$ 799	$ 1,694	$ 2,196
Average shares of common stock outstanding:				
Basic	976	973	976	972
Assumed exercise and/or distributions of stock-based awards	1	1	—	1
Diluted[(a)]	977	974	976	973
Earnings per average common share:				
Basic	$ 0.51	$ 0.79	$ 1.64	$ 2.23
Diluted	$ 0.51	$ 0.79	$ 1.64	$ 2.22

(a) The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 1 million for the three and nine months ended September 30, 2020, and less than 1 million for the three and nine months ended September 30, 2019.

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2020	2019
Cash flows from operating activities		
Net income	$ 1,519	$ 2,220
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	4,419	4,393
Asset impairments	567	174
Gain on sales of assets and businesses	(16)	(15)
Deferred income taxes and amortization of investment tax credits	164	412
Net fair value changes related to derivatives	(448)	96
Net realized and unrealized gains on NDT funds	(59)	(467)
Other non-cash operating activities	988	460
Changes in assets and liabilities:		
Accounts receivable	1,195	445
Inventories	(67)	(94)
Accounts payable and accrued expenses	(519)	(671)
Option premiums (paid) received, net	(131)	13
Collateral received (posted), net	644	(254)
Income taxes	(31)	143
Pension and non-pension postretirement benefit contributions	(580)	(377)
Other assets and liabilities	(3,423)	(1,079)
Net cash flows provided by operating activities	4,222	5,399
Cash flows from investing activities		
Capital expenditures	(5,606)	(5,259)
Proceeds from NDT fund sales	3,370	8,443
Investment in NDT funds	(3,438)	(8,437)
Collection of DPP	2,518	—
Proceeds from sales of assets and businesses	46	17
Other investing activities	(2)	21
Net cash flows used in investing activities	(3,112)	(5,215)
Cash flows from financing activities		
Changes in short-term borrowings	(689)	430
Proceeds from short-term borrowings with maturities greater than 90 days	500	—
Repayments on short-term borrowings with maturities greater than 90 days	—	(125)
Issuance of long-term debt	6,756	1,576
Retirement of long-term debt	(5,158)	(644)
Dividends paid on common stock	(1,119)	(1,055)
Proceeds from employee stock plans	62	94
Other financing activities	(104)	(63)
Net cash flows provided by financing activities	248	213
Increase in cash, cash equivalents, and restricted cash	1,358	397
Cash, cash equivalents, and restricted cash at beginning of period	1,122	1,781
Cash, cash equivalents, and restricted cash at end of period	$ 2,480	$ 2,178
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (11)	$ (96)
Increase in DPP	3,275	—
Increase in PPE related to ARO update	775	344

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2020		December 31, 2019	
ASSETS				
Current assets				
Cash and cash equivalents	$	1,858	$	587
Restricted cash and cash equivalents		485		358
Accounts receivable				
Customer accounts receivable	3,150		4,835	
Customer allowance for credit losses	(358)		(243)	
Customer accounts receivable, net		2,792		4,592
Other accounts receivable	1,576		1,631	
Other allowance for credit losses	(75)		(48)	
Other accounts receivable, net		1,501		1,583
Mark-to-market derivative assets		472		679
Unamortized energy contract assets		41		47
Inventories, net				
Fossil fuel and emission allowances		311		312
Materials and supplies		1,405		1,456
Regulatory assets		1,170		1,170
Other		2,277		1,253
Total current assets		12,312		12,037
Property, plant, and equipment (net of accumulated depreciation and amortization of $25,582 and $23,979 as of September 30, 2020 and December 31, 2019, respectively)		82,561		80,233
Deferred debits and other assets				
Regulatory assets		8,485		8,335
Nuclear decommissioning trust funds		13,432		13,190
Investments		444		464
Goodwill		6,677		6,677
Mark-to-market derivative assets		383		508
Unamortized energy contract assets		308		336
Other		3,165		3,197
Total deferred debits and other assets		32,894		32,707
Total assets[(a)]	$	127,767	$	124,977

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2020	December 31, 2019
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 1,181	$ 1,370
Long-term debt due within one year	2,077	4,710
Accounts payable	3,182	3,560
Accrued expenses	1,879	1,981
Payables to affiliates	5	5
Regulatory liabilities	575	406
Mark-to-market derivative liabilities	177	247
Unamortized energy contract liabilities	107	132
Renewable energy credit obligation	604	443
Other	1,475	1,331
Total current liabilities	11,262	14,185
Long-term debt	35,512	31,329
Long-term debt to financing trusts	390	390
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	13,058	12,351
Asset retirement obligations	11,989	10,846
Pension obligations	3,648	4,247
Non-pension postretirement benefit obligations	2,128	2,076
Spent nuclear fuel obligation	1,207	1,199
Regulatory liabilities	9,495	9,986
Mark-to-market derivative liabilities	396	393
Unamortized energy contract liabilities	266	338
Other	3,313	3,064
Total deferred credits and other liabilities	45,500	44,500
Total liabilities[a]	92,664	90,404
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 976 shares and 973 shares outstanding at September 30, 2020 and December 31, 2019, respectively)	19,362	19,274
Treasury stock, at cost (2 shares at September 30, 2020 and December 31, 2019)	(123)	(123)
Retained earnings	16,749	16,267
Accumulated other comprehensive loss, net	(3,104)	(3,194)
Total shareholders' equity	32,884	32,224
Noncontrolling interests	2,219	2,349
Total equity	35,103	34,573
Total liabilities and shareholders' equity	$ 127,767	$ 124,977

(a) Exelon's consolidated assets include $10,102 million and $9,532 million at September 30, 2020 and December 31, 2019, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $3,531 million and $3,473 million at September 30, 2020 and December 31, 2019, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 16 — Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

	Nine Months Ended September 30, 2020						
(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Shareholders' Equity
Balance, December 31, 2019	974,416	$ 19,274	$ (123)	$ 16,267	$ (3,194)	$ 2,349	$ 34,573
Net income (loss)	—	—	—	582	—	(206)	376
Long-term incentive plan activity	1,354	(4)	—	—	—	—	(4)
Employee stock purchase plan issuances	470	31	—	—	—	—	31
Changes in equity of noncontrolling interests	—	—	—	—	—	(9)	(9)
Sale of noncontrolling interests	—	2	—	—	—	—	2
Common stock dividends ($0.38/common share)	—	—	—	(374)	—	—	(374)
Other comprehensive income, net of income taxes	—	—	—	—	21	—	21
Balance, March 31, 2020	976,240	$ 19,303	$ (123)	$ 16,475	$ (3,173)	$ 2,134	$ 34,616
Net income	—	—	—	521	—	53	574
Long-term incentive plan activity	148	17	—	—	—	—	17
Employee stock purchase plan issuances	(51)	15	—	—	—	—	15
Changes in equity of noncontrolling interests	—	—	—	—	—	(19)	(19)
Sale of noncontrolling interests	—	1	—	—	—	—	1
Common stock dividends ($0.38/common share)	—	—	—	(374)	—	—	(374)
Other comprehensive income, net of income taxes	—	—	—	—	41	—	41
Balance, June 30, 2020	976,337	$ 19,336	$ (123)	$ 16,622	$ (3,132)	$ 2,168	$ 34,871
Net income	—	—	—	501	—	68	569
Long-term incentive plan activity	68	10	—	—	—	—	10
Employee stock purchase plan issuances	1,000	16	—	—	—	—	16
Changes in equity of noncontrolling interests	—	—	—	—	—	(17)	(17)
Common stock dividends ($0.38/common share)	—	—	—	(374)	—	—	(374)
Other comprehensive income net of income taxes	—	—	—	—	28	—	28
Balance, September 30, 2020	977,405	$ 19,362	$ (123)	$ 16,749	$ (3,104)	$ 2,219	$ 35,103

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

	Nine Months Ended September 30, 2019						
(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Shareholders' Equity
Balance, December 31, 2018	970,020	$ 19,116	$ (123)	$ 14,766	$ (2,995)	$ 2,306	$ 33,070
Net income	—	—	—	907	—	59	966
Long-term incentive plan activity	2,446	(3)	—	—	—	—	(3)
Employee stock purchase plan issuances	320	51	—	—	—	—	51
Changes in equity of noncontrolling interests	—	—	—	—	—	(17)	(17)
Sale of noncontrolling interests	—	7	—	—	—	—	7
Common stock dividends ($0.36/common share)	—	—	—	(352)	—	—	(352)
Other comprehensive loss, net of income taxes	—	—	—	—	(17)	(1)	(18)
Balance, March 31, 2019	972,786	$ 19,171	$ (123)	$ 15,321	$ (3,012)	$ 2,347	$ 33,704
Net income	—	—	—	484	—	10	494
Long-term incentive plan activity	320	14	—	—	—	—	14
Employee stock purchase plan issuances	311	24	—	—	—	—	24
Changes in equity of noncontrolling interests	—	—	—	—	—	3	3
Common stock dividends ($0.36/common share)	—	—	—	(353)	—	—	(353)
Other comprehensive income, net of income taxes	—	—	—	—	22	(1)	21
Balance, June 30, 2019	973,417	$ 19,209	$ (123)	$ 15,452	$ (2,990)	$ 2,359	$ 33,907
Net Income (loss)	—	—	—	772	—	(12)	760
Long-term incentive plan activity	207	10	—	—	—	—	10
Employee stock purchase plan issuances	317	19	—	—	—	—	19
Changes in equity of noncontrolling interests	—	—	—	—	—	(18)	(18)
Common stock dividends ($0.36/common share)	—	—	—	(353)	—	—	(353)
Other comprehensive income, net of income taxes	—	—	—	—	27	—	27
Balance, September 30, 2019	973,941	$ 19,238	$ (123)	$ 15,871	$ (2,963)	$ 2,329	$ 34,352

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Operating revenues				
Operating revenues	$ 4,328	$ 4,499	$ 12,340	$ 13,436
Operating revenues from affiliates	331	275	932	844
Total operating revenues	4,659	4,774	13,272	14,280
Operating expenses				
Purchased power and fuel	2,311	2,648	6,967	8,141
Purchased power and fuel from affiliates	3	3	(6)	7
Operating and maintenance	1,605	947	3,779	3,131
Operating and maintenance from affiliates	132	140	409	439
Depreciation and amortization	558	407	1,161	1,221
Taxes other than income taxes	118	129	364	394
Total operating expenses	4,727	4,274	12,674	13,333
(Loss) Gain on sales of assets and businesses	—	(18)	12	15
Operating (loss) income	(68)	482	610	962
Other income and (deductions)				
Interest expense, net	(72)	(101)	(251)	(310)
Interest expense to affiliates	(8)	(8)	(26)	(26)
Other, net	367	128	199	729
Total other income and (deductions)	287	19	(78)	393
Income before income taxes	219	501	532	1,355
Income taxes	100	87	41	388
Equity in losses of unconsolidated affiliates	(2)	(170)	(6)	(183)
Net income	117	244	485	784
Net income (loss) attributable to noncontrolling interests	68	(13)	(85)	56
Net income attributable to membership interest	$ 49	$ 257	$ 570	$ 728
Comprehensive income, net of income taxes				
Net income	$ 117	$ 244	$ 485	$ 784
Other comprehensive income (loss), net of income taxes				
Unrealized loss on cash flow hedges	—	—	(1)	—
Unrealized gain on investments in unconsolidated affiliates	—	5	—	1
Unrealized gain (loss) on foreign currency translation	3	(2)	(3)	2
Other comprehensive income (loss)	3	3	(4)	3
Comprehensive income	120	247	481	787
Comprehensive income (loss) attributable to noncontrolling interests	68	(10)	(85)	57
Comprehensive income attributable to membership interest	$ 52	$ 257	$ 566	$ 730

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2020	2019
Cash flows from operating activities		
Net income	$ 485	$ 784
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	2,266	2,377
Asset impairments	552	174
Gain on sales of assets and businesses	(12)	(15)
Deferred income taxes and amortization of investment tax credits	(51)	201
Net fair value changes related to derivatives	(448)	102
Net realized and unrealized gains on NDT funds	(59)	(467)
Other non-cash operating activities	293	(95)
Changes in assets and liabilities:		
Accounts receivable	1,463	395
Receivables from and payables to affiliates, net	75	(12)
Inventories	(65)	(36)
Accounts payable and accrued expenses	(619)	(428)
Option premiums (paid) received, net	(131)	13
Collateral posted, net	640	(292)
Income taxes	112	327
Pension and non-pension postretirement benefit contributions	(249)	(165)
Other assets and liabilities	(2,889)	(390)
Net cash flows provided by operating activities	1,363	2,473
Cash flows from investing activities		
Capital expenditures	(1,212)	(1,282)
Proceeds from NDT fund sales	3,370	8,443
Investment in NDT funds	(3,438)	(8,437)
Collection of DPP	2,518	—
Proceeds from sales of assets and businesses	46	17
Other investing activities	5	(6)
Net cash flows provided by (used in) investing activities	1,289	(1,265)
Cash flows from financing activities		
Changes in short-term borrowings	(280)	—
Proceeds from short-term borrowings with maturities greater than 90 days	500	—
Issuance of long-term debt	2,405	41
Retirement of long-term debt	(3,613)	(196)
Changes in Exelon intercompany money pool	—	(100)
Distributions to member	(1,406)	(674)
Contributions from member	64	—
Other financing activities	(48)	(37)
Net cash flows used in financing activities	(2,378)	(966)
Increase in cash, cash equivalents, and restricted cash	274	242
Cash, cash equivalents, and restricted cash at beginning of period	449	903
Cash, cash equivalents, and restricted cash at end of period	$ 723	$ 1,145
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (77)	$ (24)
Increase in DPP	3,275	—
Increase in PPE related to ARO update	775	342

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2020		December 31, 2019	
ASSETS				
Current assets				
Cash and cash equivalents	$	623	$	303
Restricted cash and cash equivalents		100		146
Accounts receivable				
Customer accounts receivable	1,089		2,973	
Customer allowance for credit losses	(33)		(80)	
Customer accounts receivable, net		1,056		2,893
Other accounts receivable	311		619	
Other accounts receivable, net		311		619
Mark-to-market derivative assets		471		675
Receivables from affiliates		109		190
Unamortized energy contract assets		41		47
Inventories, net				
Fossil fuel and emission allowances		238		236
Materials and supplies		971		1,026
Renewable energy credits		576		336
Other		1,387		605
Total current assets		5,883		7,076
Property, plant, and equipment (net of accumulated depreciation and amortization of $12,588 and $12,017 as of September 30, 2020 and December 31, 2019, respectively)		23,709		24,193
Deferred debits and other assets				
Nuclear decommissioning trust funds		13,432		13,190
Investments		197		235
Goodwill		47		47
Mark-to-market derivative assets		383		508
Prepaid pension asset		1,584		1,438
Unamortized energy contract assets		308		336
Deferred income taxes		9		12
Other		1,820		1,960
Total deferred debits and other assets		17,780		17,726
Total assets[(a)]	$	47,372	$	48,995

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2020	December 31, 2019
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 540	$ 320
Long-term debt due within one year	203	2,624
Long-term debt to affiliates due within one year	551	558
Accounts payable	1,109	1,692
Accrued expenses	699	786
Payables to affiliates	113	117
Mark-to-market derivative liabilities	147	215
Unamortized energy contract liabilities	8	17
Renewable energy credit obligation	604	443
Other	437	517
Total current liabilities	4,411	7,289
Long-term debt	5,677	4,464
Long-term debt to affiliates	325	328
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,715	3,752
Asset retirement obligations	11,744	10,603
Non-pension postretirement benefit obligations	864	878
Spent nuclear fuel obligation	1,207	1,199
Payables to affiliates	2,888	3,103
Mark-to-market derivative liabilities	121	123
Unamortized energy contract liabilities	8	11
Other	1,488	1,415
Total deferred credits and other liabilities	22,035	21,084
Total liabilities[(a)]	32,448	33,165
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	9,633	9,566
Undistributed earnings	3,114	3,950
Accumulated other comprehensive loss, net	(36)	(32)
Total member's equity	12,711	13,484
Noncontrolling interests	2,213	2,346
Total equity	14,924	15,830
Total liabilities and equity	$ 47,372	$ 48,995

(a) Generation's consolidated assets include $10,082 million and $9,512 million at September 30, 2020 and December 31, 2019, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include $3,499 million and $3,429 million at September 30, 2020 and December 31, 2019, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 16 — Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Unaudited)

	Nine Months Ended September 30, 2020				
	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2019	$ 9,566	$ 3,950	$ (32)	$ 2,346	$ 15,830
Net income (loss)	—	45	—	(206)	(161)
Changes in equity of noncontrolling interests	—	—	—	(11)	(11)
Sale of noncontrolling interests	2	—	—	—	2
Distributions to member	—	(468)	—	—	(468)
Other comprehensive loss, net of income taxes	—	—	(9)	—	(9)
Balance, March 31, 2020	$ 9,568	$ 3,527	$ (41)	$ 2,129	$ 15,183
Net income	—	476	—	53	529
Changes in equity of noncontrolling interests	—	—	—	(19)	(19)
Sale of noncontrolling interests	1	—	—	—	1
Distributions to member	—	(469)	—	—	(469)
Other comprehensive loss, net of income taxes	—	—	2	—	2
Balance, June 30, 2020	$ 9,569	$ 3,534	$ (39)	$ 2,163	$ 15,227
Net income	—	49	—	68	117
Changes in equity of noncontrolling interests	—	—	—	(18)	(18)
Sale of noncontrolling interests	—	—	—	—	—
Contribution from member	64	—	—	—	64
Distributions to member	—	(469)	—	—	(469)
Other comprehensive income, net of income taxes	—	—	3	—	3
Balance, September 30, 2020	$ 9,633	$ 3,114	$ (36)	$ 2,213	$ 14,924

See the Combined Notes to Consolidated Financial Statements

(In millions)	Nine Months Ended September 30, 2019				
	Member's Equity				
	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2018	$ 9,518	$ 3,724	$ (38)	$ 2,304	$ 15,508
Net income	—	363	—	59	422
Changes in equity of noncontrolling interests	—	—	—	(17)	(17)
Sale of noncontrolling interests	7	—	—	—	7
Distributions to member	—	(225)	—	—	(225)
Other comprehensive income, net of income taxes	—	—	2	(1)	1
Balance, March 31, 2019	$ 9,525	$ 3,862	$ (36)	$ 2,345	$ 15,696
Net income	—	108	—	10	118
Changes in equity of noncontrolling interests	—	—	—	3	3
Distributions to member	—	(224)	—	—	(224)
Other comprehensive income, net of income taxes	—	—	—	(1)	(1)
Balance, June 30, 2019	$ 9,525	$ 3,746	$ (36)	$ 2,357	$ 15,592
Net income (loss)	—	257	—	(13)	244
Changes in equity of noncontrolling interests	—	—	—	(18)	(18)
Distributions to member	—	(225)	—	—	(225)
Balance, September 30, 2019	$ 9,525	$ 3,778	$ (36)	$ 2,326	$ 15,593

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Operating revenues				
Electric operating revenues	$ 1,666	$ 1,635	$ 4,519	$ 4,427
Revenues from alternative revenue programs	(38)	(56)	(51)	(98)
Operating revenues from affiliates	15	4	31	13
Total operating revenues	1,643	1,583	4,499	4,342
Operating expenses				
Purchased power	535	494	1,305	1,199
Purchased power from affiliate	71	83	252	270
Operating and maintenance	252	267	964	771
Operating and maintenance from affiliate	69	73	209	196
Depreciation and amortization	294	259	841	767
Taxes other than income taxes	81	80	227	228
Total operating expenses	1,302	1,256	3,798	3,431
Gain on sales of assets	—	1	—	4
Operating income	341	328	701	915
Other income and (deductions)				
Interest expense, net	(92)	(87)	(277)	(258)
Interest expense to affiliates	(3)	(4)	(10)	(10)
Other, net	10	8	32	27
Total other income and (deductions)	(85)	(83)	(255)	(241)
Income before income taxes	256	245	446	674
Income taxes	60	45	142	130
Net income	$ 196	$ 200	$ 304	$ 544
Comprehensive income	$ 196	$ 200	$ 304	$ 544

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

(In millions)	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Cash flows from operating activities		
Net income	$ 304	$ 544
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, and accretion	841	767
Asset impairments	15	—
Deferred income taxes and amortization of investment tax credits	205	115
Other non-cash operating activities	354	180
Changes in assets and liabilities:		
Accounts receivable	(104)	(38)
Receivables from and payables to affiliates, net	(13)	(27)
Inventories	(2)	(16)
Accounts payable and accrued expenses	21	(132)
Collateral received (posted), net	3	43
Income taxes	(22)	25
Pension and non-pension postretirement benefit contributions	(145)	(71)
Other assets and liabilities	(380)	(245)
Net cash flows provided by operating activities	1,077	1,145
Cash flows from investing activities		
Capital expenditures	(1,583)	(1,413)
Other investing activities	—	25
Net cash flows used in investing activities	(1,583)	(1,388)
Cash flows from financing activities		
Changes in short-term borrowings	11	387
Issuance of long-term debt	1,000	400
Retirement of long-term debt	(500)	(300)
Dividends paid on common stock	(374)	(380)
Contributions from parent	488	187
Other financing activities	(14)	(10)
Net cash flows provided by financing activities	611	284
Increase in cash, cash equivalents, and restricted cash	105	41
Cash, cash equivalents, and restricted cash at beginning of period	403	330
Cash, cash equivalents, and restricted cash at end of period	$ 508	$ 371
Supplemental cash flow information		
Increase (decrease) in capital expenditures not paid	$ 49	$ (52)

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2020		December 31, 2019	
ASSETS				
Current assets				
Cash and cash equivalents	$	76	$	90
Restricted cash and cash equivalents		305		150
Accounts receivable				
Customer accounts receivable	707		604	
Customer allowance for credit losses	(105)		(59)	
Customer accounts receivable, net		602		545
Other accounts receivable	309		306	
Other allowance for credit losses	(27)		(20)	
Other accounts receivable, net		282		286
Receivables from affiliates		20		28
Inventories, net		160		159
Regulatory assets		274		281
Other		59		44
Total current assets		1,778		1,583
Property, plant, and equipment (net of accumulated depreciation and amortization of $5,533 and $5,168 as of September 30, 2020 and December 31, 2019, respectively)		24,081		23,107
Deferred debits and other assets				
Regulatory assets		1,742		1,480
Investments		6		6
Goodwill		2,625		2,625
Receivables from affiliates		2,445		2,622
Prepaid pension asset		1,050		995
Other		516		347
Total deferred debits and other assets		8,384		8,075
Total assets	$	34,243	$	32,765

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2020	December 31, 2019
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 141	$ 130
Long-term debt due within one year	350	500
Accounts payable	671	527
Accrued expenses	282	385
Payables to affiliates	82	103
Customer deposits	100	118
Regulatory liabilities	251	200
Mark-to-market derivative liabilities	30	32
Deferred Prosecution Agreement payments	200	—
Other	140	122
Total current liabilities	2,247	2,117
Long-term debt	8,631	7,991
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,299	4,021
Asset retirement obligations	126	128
Non-pension postretirement benefits obligations	175	180
Regulatory liabilities	6,420	6,542
Mark-to-market derivative liabilities	274	269
Other	771	635
Total deferred credits and other liabilities	12,065	11,775
Total liabilities	23,148	22,088
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	8,060	7,572
Retained deficit unappropriated	(1,700)	(1,639)
Retained earnings appropriated	3,147	3,156
Total shareholders' equity	11,095	10,677
Total liabilities and shareholders' equity	$ 34,243	$ 32,765

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
	Nine Months Ended September 30, 2020				
Balance, December 31, 2019	$ 1,588	$ 7,572	$ (1,639)	$ 3,156	$ 10,677
Net income	—	—	168	—	168
Appropriation of retained earnings for future dividends	—	—	(168)	168	—
Common stock dividends	—	—	—	(125)	(125)
Contributions from parent	—	125	—	—	125
Balance, March 31, 2020	$ 1,588	$ 7,697	$ (1,639)	$ 3,199	$ 10,845
Net loss	—	—	(61)	—	(61)
Common stock dividends	—	—	—	(124)	(124)
Contributions from parent	—	124	—	—	124
Balance, June 30, 2020	$ 1,588	$ 7,821	$ (1,700)	$ 3,075	$ 10,784
Net income	—	—	196	—	196
Appropriation of retained earnings for future dividends	—	—	(196)	196	—
Common stock dividends	—	—	—	(124)	(124)
Contributions from parent	—	239	—	—	239
Balance, September 30, 2020	$ 1,588	$ 8,060	$ (1,700)	$ 3,147	$ 11,095

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
	Nine Months Ended September 30, 2019				
Balance, December 31, 2018	$ 1,588	$ 7,322	$ (1,639)	$ 2,976	$ 10,247
Net income	—	—	157	—	157
Appropriation of retained earnings for future dividends	—	—	(157)	157	—
Common stock dividends	—	—	—	(127)	(127)
Contributions from parent	—	63	—	—	63
Balance, March 31, 2019	$ 1,588	$ 7,385	$ (1,639)	$ 3,006	$ 10,340
Net income	—	—	186	—	186
Appropriation of retained earnings for future dividends	—	—	(186)	186	—
Common stock dividends	—	—	—	(127)	(127)
Contributions from parent	—	61	—	—	61
Balance, June 30, 2019	$ 1,588	$ 7,446	$ (1,639)	$ 3,065	$ 10,460
Net income	—	—	200	—	200
Appropriation of retained earnings for future dividends	—	—	(200)	200	—
Common stock dividends	—	—	—	(126)	(126)
Contributions from parent	—	63	—	—	63
Balance, September 30, 2019	$ 1,588	$ 7,509	$ (1,639)	$ 3,139	$ 10,597

See the Combined Notes to Consolidated Financial Statements

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2020	2019	2020	2019
Operating revenues				
Electric operating revenues	$ 751	$ 726	$ 1,931	$ 1,914
Natural gas operating revenues	54	62	358	431
Revenues from alternative revenue programs	5	(11)	10	(16)
Operating revenues from affiliates	3	1	7	4
Total operating revenues	813	778	2,306	2,333
Operating expenses				
Purchased power	190	185	495	461
Purchased fuel	12	18	129	184
Purchased power from affiliate	67	43	144	122
Operating and maintenance	214	182	628	531
Operating and maintenance from affiliates	37	37	114	112
Depreciation and amortization	85	83	259	247
Taxes other than income taxes	53	47	131	126
Total operating expenses	658	595	1,900	1,783
Operating income	155	183	406	550
Other income and (deductions)				
Interest expense, net	(36)	(30)	(100)	(91)
Interest expense to affiliates	(3)	(3)	(8)	(9)
Other, net	6	4	12	11
Total other income and (deductions)	(33)	(29)	(96)	(89)
Income before income taxes	122	154	310	461
Income taxes	(16)	14	(7)	51
Net income	$ 138	$ 140	$ 317	$ 410
Comprehensive income	$ 138	$ 140	$ 317	$ 410

See the Combined Notes to Consolidated Financial Statements

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

	Nine Months Ended September 30,	
(In millions)	2020	2019
Cash flows from operating activities		
Net income	$ 317	$ 410
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	259	247
Deferred income taxes and amortization of investment tax credits	(5)	6
Other non-cash operating activities	27	28
Changes in assets and liabilities:		
Accounts receivable	(2)	46
Receivables from and payables to affiliates, net	(7)	(12)
Inventories	(3)	(3)
Accounts payable and accrued expenses	32	(32)
Income taxes	48	(15)
Pension and non-pension postretirement benefit contributions	(18)	(26)
Other assets and liabilities	(13)	(111)
Net cash flows provided by operating activities	635	538
Cash flows from investing activities		
Capital expenditures	(824)	(675)
Changes in Exelon intercompany money pool	68	—
Other investing activities	4	7
Net cash flows used in investing activities	(752)	(668)
Cash flows from financing activities		
Issuance of long-term debt	350	325
Dividends paid on common stock	(255)	(268)
Contributions from parent	248	174
Other financing activities	(4)	(6)
Net cash flows provided by financing activities	339	225
Increase in cash, cash equivalents, and restricted cash	222	95
Cash, cash equivalents, and restricted cash at beginning of period	27	135
Cash, cash equivalents, and restricted cash at end of period	$ 249	$ 230
Supplemental cash flow information		
Increase in capital expenditures not paid	$ 28	$ 42

See the Combined Notes to Consolidated Financial Statements

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

(In millions)		September 30, 2020		December 31, 2019
ASSETS				
Current assets				
Cash and cash equivalents		$ 242		$ 21
Restricted cash and cash equivalents		7		6
Accounts receivable				
Customer accounts receivable	412		412	
Customer allowance for credit losses	(96)		(55)	
Customer accounts receivable, net		316		357
Other accounts receivable	126		145	
Other allowance for credit losses	(7)		(7)	
Other accounts receivable, net		119		138
Receivables from affiliates		—		1
Receivable from Exelon intercompany money pool		—		68
Inventories, net				
Fossil fuel		36		36
Materials and supplies		37		35
Prepaid utility taxes		35		—
Regulatory assets		38		41
Other		23		19
Total current assets		853		722
Property, plant, and equipment (net of accumulated depreciation and amortization of $3,804 and $3,718 as of September 30, 2020 and December 31, 2019, respectively)		9,912		9,292
Deferred debits and other assets				
Regulatory assets		692		554
Investments		29		27
Receivables from affiliates		443		480
Prepaid pension asset		377		365
Other		28		29
Total deferred debits and other assets		1,569		1,455
Total assets		$ 12,334		$ 11,469

See the Combined Notes to Consolidated Financial Statements

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

(In millions)		September 30, 2020		December 31, 2019
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current liabilities				
Long-term debt due within one year	$	300	$	—
Accounts payable		443		387
Accrued expenses		124		101
Payables to affiliates		47		55
Customer deposits		63		69
Regulatory liabilities		129		91
Other		27		19
Total current liabilities		1,133		722
Long-term debt		3,453		3,405
Long-term debt to financing trusts		184		184
Deferred credits and other liabilities				
Deferred income taxes and unamortized investment tax credits		2,194		2,080
Asset retirement obligations		29		28
Non-pension postretirement benefits obligations		286		288
Regulatory liabilities		471		510
Other		96		74
Total deferred credits and other liabilities		3,076		2,980
Total liabilities		7,846		7,291
Commitments and contingencies				
Shareholder's equity				
Common stock		3,014		2,766
Retained earnings		1,474		1,412
Total shareholder's equity		4,488		4,178
Total liabilities and shareholder's equity	$	12,334	$	11,469

See the Combined Notes to Consolidated Financial Statements

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

	Nine months ended September 30, 2020		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2019	$ 2,766	$ 1,412	$ 4,178
Net income	—	140	140
Common stock dividends	—	(85)	(85)
Contributions from parent	231	—	231
Balance, March 31, 2020	$ 2,997	$ 1,467	$ 4,464
Net income	—	39	39
Common stock dividends	—	(85)	(85)
Balance, June 30, 2020	$ 2,997	$ 1,421	$ 4,418
Net income	—	138	138
Common stock dividends	—	(85)	(85)
Contributions from parent	17	—	17
Balance, September 30, 2020	$ 3,014	$ 1,474	$ 4,488

	Nine months ended September 30, 2019		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2018	$ 2,578	$ 1,242	$ 3,820
Net income	—	168	168
Common stock dividends	—	(90)	(90)
Contributions from parent	145	—	145
Balance, March 31, 2019	$ 2,723	$ 1,320	$ 4,043
Net income	—	102	102
Common stock dividends	—	(90)	(90)
Balance, June 30, 2019	$ 2,723	$ 1,332	$ 4,055
Net income	—	140	140
Common stock dividends	—	(88)	(88)
Contributions from parent	29	—	29
Balance, September 30, 2019	$ 2,752	$ 1,384	$ 4,136

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Operating revenues				
Electric operating revenues	$ 649	$ 623	$ 1,775	$ 1,814
Natural gas operating revenues	85	79	503	484
Revenues from alternative revenue programs	(9)	(5)	(10)	11
Operating revenues from affiliates	6	6	16	18
Total operating revenues	731	703	2,284	2,327
Operating expenses				
Purchased power	155	159	376	480
Purchased fuel	12	12	106	128
Purchased power and fuel from affiliate	83	64	249	196
Operating and maintenance	152	157	445	451
Operating and maintenance from affiliates	39	39	122	118
Depreciation and amortization	133	116	405	368
Taxes other than income taxes	68	65	200	195
Total operating expenses	642	612	1,903	1,936
Operating income	89	91	381	391
Other income and (deductions)				
Interest expense, net	(34)	(31)	(99)	(89)
Other, net	6	7	17	18
Total other income and (deductions)	(28)	(24)	(82)	(71)
Income before income taxes	61	67	299	320
Income taxes	8	12	26	59
Net income	$ 53	$ 55	$ 273	$ 261
Comprehensive income	$ 53	$ 55	$ 273	$ 261

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2020	2019
Cash flows from operating activities		
Net income	$ 273	$ 261
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	405	368
Deferred income taxes and amortization of investment tax credits	35	66
Other non-cash operating activities	82	63
Changes in assets and liabilities:		
Accounts receivable	(19)	110
Receivables from and payables to affiliates, net	(27)	(14)
Inventories	2	(5)
Accounts payable and accrued expenses	53	(28)
Collateral posted, net	—	(5)
Income taxes	46	(43)
Pension and non-pension postretirement benefit contributions	(74)	(45)
Other assets and liabilities	(50)	(65)
Net cash flows provided by operating activities	726	663
Cash flows from investing activities		
Capital expenditures	(838)	(842)
Other investing activities	—	4
Net cash flows used in investing activities	(838)	(838)
Cash flows from financing activities		
Changes in short-term borrowings	(76)	(35)
Issuance of long-term debt	400	400
Dividends paid on common stock	(186)	(169)
Contributions from parent	284	104
Other financing activities	(8)	(7)
Net cash flows provided by financing activities	414	293
Increase in cash, cash equivalents, and restricted cash	302	118
Cash, cash equivalents, and restricted cash at beginning of period	25	13
Cash, cash equivalents, and restricted cash at end of period	$ 327	$ 131
Supplemental cash flow information		
Increase in capital expenditures not paid	$ 7	$ 6

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2020		December 31, 2019	
ASSETS				
Current assets				
Cash and cash equivalents	$	326	$	24
Restricted cash and cash equivalents		1		1
Accounts receivable				
Customer accounts receivable	357		329	
Customer allowance for credit losses	(35)		(12)	
Customer accounts receivable, net		322		317
Other accounts receivable	114		152	
Other allowance for credit losses	(9)		(5)	
Other accounts receivable, net		105		147
Receivables from affiliates		—		1
Inventories, net				
Fossil fuel		31		30
Materials and supplies		43		46
Prepaid utility taxes		—		78
Regulatory assets		167		183
Other		6		6
Total current assets		1,001		833
Property, plant, and equipment (net of accumulated depreciation and amortization of $3,963 and $3,834 as of September 30, 2020 and December 31, 2019, respectively)		9,541		8,990
Deferred debits and other assets				
Regulatory assets		473		454
Investments		8		7
Prepaid pension asset		283		264
Other		64		86
Total deferred debits and other assets		828		811
Total assets	$	11,370	$	10,634

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2020	December 31, 2019
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 76
Accounts payable	273	243
Accrued expenses	178	152
Payables to affiliates	39	66
Customer deposits	115	120
Regulatory liabilities	39	33
Other	76	63
Total current liabilities	720	753
Long-term debt	3,664	3,270
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,504	1,396
Asset retirement obligations	24	22
Non-pension postretirement benefits obligations	190	199
Regulatory liabilities	1,121	1,195
Other	93	116
Total deferred credits and other liabilities	2,932	2,928
Total liabilities	7,316	6,951
Commitments and contingencies		
Shareholder's equity		
Common stock	2,191	1,907
Retained earnings	1,863	1,776
Total shareholder's equity	4,054	3,683
Total liabilities and shareholder's equity	$ 11,370	$ 10,634

See the Combined Notes to Consolidated Financial Statements

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

	Nine Months Ended September 30, 2020		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2019	$ 1,907	$ 1,776	$ 3,683
Net income	—	181	181
Common stock dividends	—	(62)	(62)
Balance, March 31, 2020	$ 1,907	$ 1,895	$ 3,802
Net income	—	39	39
Common stock dividends	—	(62)	(62)
Contributions from parent	26	—	26
Balance, June 30, 2020	$ 1,933	$ 1,872	$ 3,805
Net income	—	53	53
Common stock dividends	—	(62)	(62)
Contributions from parent	258	—	258
Balance, September 30, 2020	$ 2,191	$ 1,863	$ 4,054

	Nine Months Ended September 30, 2019		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2018	$ 1,714	$ 1,640	$ 3,354
Net income	—	160	160
Common stock dividends	—	(56)	(56)
Balance, March 31, 2019	$ 1,714	$ 1,744	$ 3,458
Net income	—	45	45
Common stock dividends	—	(55)	(55)
Balance, June 30, 2019	$ 1,714	$ 1,734	$ 3,448
Net income	—	55	55
Common stock dividends	—	(57)	(57)
Contributions from parent	104	—	104
Balance, September 30, 2019	$ 1,818	$ 1,732	$ 3,550

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

(In millions)	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Operating revenues				
Electric operating revenues	$ 1,308	$ 1,365	$ 3,440	$ 3,570
Natural gas operating revenues	23	20	116	115
Revenues from alternative revenue programs	31	(9)	(15)	4
Operating revenues from affiliates	6	4	13	11
Total operating revenues	1,368	1,380	3,554	3,700
Operating expenses				
Purchased power	393	428	979	1,086
Purchased fuel	7	8	49	51
Purchased power from affiliates	106	83	288	254
Operating and maintenance	237	254	702	706
Operating and maintenance from affiliates	38	36	111	105
Depreciation and amortization	200	193	585	562
Taxes other than income taxes	121	122	343	342
Total operating expenses	1,102	1,124	3,057	3,106
Gain on sales of assets	—	—	2	—
Operating income	266	256	499	594
Other income and (deductions)				
Interest expense, net	(67)	(66)	(201)	(197)
Other, net	16	13	42	39
Total other income and (deductions)	(51)	(53)	(159)	(158)
Income before income taxes	215	203	340	436
Income taxes	(1)	14	(77)	25
Equity in earnings of unconsolidated affiliate	—	—	1	1
Net income	$ 216	$ 189	$ 418	$ 412
Comprehensive income	$ 216	$ 189	$ 418	$ 412

See the Combined Notes to Consolidated Financial Statements

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Cash flows from operating activities		
Net income	$ 418	$ 412
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	585	562
Deferred income taxes and amortization of investment tax credits	(99)	8
Other non-cash operating activities	115	122
Changes in assets and liabilities:		
Accounts receivable	(121)	(64)
Receivables from and payables to affiliates, net	(26)	1
Inventories	(2)	(36)
Accounts payable and accrued expenses	57	—
Income taxes	(14)	(11)
Pension and non-pension postretirement benefit contributions	(35)	(15)
Other assets and liabilities	(61)	(102)
Net cash flows provided by operating activities	817	877
Cash flows from investing activities		
Capital expenditures	(1,072)	(1,006)
Other investing activities	3	3
Net cash flows used in investing activities	(1,069)	(1,003)
Cash flows from financing activities		
Changes in short-term borrowings	(208)	78
Repayments of short-term borrowings with maturities greater than 90 days	—	(125)
Issuance of long-term debt	601	410
Retirement of long-term debt	(119)	(130)
Changes in Exelon intercompany money pool	9	10
Distributions to member	(451)	(429)
Contributions from member	493	283
Other financing activities	(10)	(5)
Net cash flows provided by financing activities	315	92
Increase (decrease) in cash, cash equivalents, and restricted cash	63	(34)
Cash, cash equivalents, and restricted cash at beginning of period	181	186
Cash, cash equivalents, and restricted cash at end of period	$ 244	$ 152
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (5)	$ (62)

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2020		December 31, 2019	
ASSETS				
Current assets				
Cash and cash equivalents	$	196	$	131
Restricted cash and cash equivalents		38		36
Accounts receivable				
Customer accounts receivable	584		516	
Customer allowance for credit losses	(89)		(37)	
Customer accounts receivable, net		495		479
Other accounts receivable	244		190	
Other allowance for credit losses	(32)		(16)	
Other accounts receivable, net		212		174
Receivables from affiliates		—		1
Inventories, net				
Fossil fuel		7		8
Materials and supplies		194		190
Regulatory assets		440		412
Other		52		49
Total current assets		1,634		1,480
Property, plant, and equipment (net of accumulated depreciation and amortization of $1,692 and $1,213 as of September 30, 2020 and December 31, 2019, respectively)		14,954		14,296
Deferred debits and other assets				
Regulatory assets		1,972		2,061
Investments		138		135
Goodwill		4,005		4,005
Prepaid pension asset		381		406
Deferred income taxes		10		13
Other		300		323
Total deferred debits and other assets		6,806		6,943
Total assets[(a)]	$	23,394	$	22,719

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2020	December 31, 2019
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 208
Long-term debt due within one year	349	103
Accounts payable	507	462
Accrued expenses	279	296
Payables to affiliates	71	98
Borrowings from Exelon intercompany money pool	21	12
Customer deposits	111	117
Regulatory liabilities	143	70
Unamortized energy contract liabilities	98	115
Other	144	131
Total current liabilities	1,723	1,612
Long-term debt	6,671	6,460
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,409	2,278
Asset retirement obligations	58	57
Non-pension postretirement benefit obligations	85	93
Regulatory liabilities	1,471	1,707
Unamortized energy contract liabilities	258	327
Other	650	577
Total deferred credits and other liabilities	4,931	5,039
Total liabilities[(a)]	13,325	13,111
Commitments and contingencies		
Member's equity		
Membership interest	10,112	9,618
Undistributed losses	(43)	(10)
Total member's equity	10,069	9,608
Total liabilities and member's equity	$ 23,394	$ 22,719

(a) PHI's consolidated total assets include $20 million and $20 million at September 30, 2020 and December 31, 2019, respectively, of PHI's consolidated VIE that can only be used to settle the liabilities of the VIE. PHI's consolidated total liabilities include $32 million and $44 million at September 30, 2020 and December 31, 2019, respectively, of PHI's consolidated VIE for which the VIE creditors do not have recourse to PHI. See Note 16 — Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

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

	Nine Months Ended September 30, 2020		
(In millions)	Membership Interest	Undistributed Earnings (Losses)	Member's Equity
Balance, December 31, 2019	$ 9,618	$ (10)	$ 9,608
Net income	—	108	108
Distributions to member	—	(134)	(134)
Contributions from member	144	—	144
Balance, March 31, 2020	$ 9,762	$ (36)	$ 9,726
Net income	—	94	94
Distributions to member	—	(134)	(134)
Contributions from member	215	—	215
Balance, June 30, 2020	$ 9,977	$ (76)	$ 9,901
Net income	—	216	216
Distributions to member	—	(183)	(183)
Contributions from member	135	—	135
Balance, September 30, 2020	$ 10,112	$ (43)	$ 10,069

	Nine Months Ended September 30, 2019		
(In millions)	Membership Interest	Undistributed Earnings (Losses)	Member's Equity
Balance, December 31, 2018	$ 9,220	$ 62	$ 9,282
Net income	—	117	117
Distributions to member	—	(128)	(128)
Contributions from member	19	—	19
Balance, March 31, 2019	$ 9,239	$ 51	$ 9,290
Net income	—	106	106
Distributions to member	—	(88)	(88)
Contributions from member	264	—	264
Balance, June 30, 2019	$ 9,503	$ 69	$ 9,572
Net income	—	189	189
Distributions to member	—	(213)	(213)
Balance, September 30, 2019	$ 9,503	$ 45	$ 9,548

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Operating revenues				
Electric operating revenues	$ 590	$ 643	$ 1,624	$ 1,733
Revenues from alternative revenue programs	18	(3)	20	10
Operating revenues from affiliates	3	2	6	5
Total operating revenues	611	642	1,650	1,748
Operating expenses				
Purchased power	83	116	248	325
Purchased power from affiliate	80	65	219	188
Operating and maintenance	57	85	184	208
Operating and maintenance from affiliates	49	50	152	156
Depreciation and amortization	96	95	282	281
Taxes other than income taxes	100	104	279	286
Total operating expenses	465	515	1,364	1,444
Operating income	146	127	286	304
Other income and (deductions)				
Interest expense, net	(35)	(33)	(103)	(100)
Other, net	10	9	28	22
Total other income and (deductions)	(25)	(24)	(75)	(78)
Income before income taxes	121	103	211	226
Income taxes	3	5	(16)	9
Net income	$ 118	$ 98	$ 227	$ 217
Comprehensive income	$ 118	$ 98	$ 227	$ 217

See the Combined Notes to Consolidated Financial Statements

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30, 2020	2019
Cash flows from operating activities		
Net income	$ 227	$ 217
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	282	281
Deferred income taxes and amortization of investment tax credits	(36)	12
Other non-cash operating activities	6	43
Changes in assets and liabilities:		
Accounts receivable	(61)	(49)
Receivables from and payables to affiliates, net	(23)	4
Inventories	2	(23)
Accounts payable and accrued expenses	36	(12)
Income taxes	(11)	(23)
Pension and non-pension postretirement benefit contributions	(8)	(10)
Other assets and liabilities	15	(55)
Net cash flows provided by operating activities	429	385
Cash flows from investing activities		
Capital expenditures	(512)	(455)
Changes in PHI intercompany money pool	(117)	—
Other investing activities	(3)	2
Net cash flows used in investing activities	(632)	(453)
Cash flows from financing activities		
Changes in short-term borrowings	(82)	(28)
Issuance of long-term debt	300	260
Retirement of long-term debt	(2)	(118)
Dividends paid on common stock	(174)	(173)
Contributions from parent	262	129
Other financing activities	(6)	(3)
Net cash flows provided by financing activities	298	67
Increase (decrease) in cash, cash equivalents, and restricted cash	95	(1)
Cash, cash equivalents, and restricted cash at beginning of period	63	53
Cash, cash equivalents, and restricted cash at end of period	$ 158	$ 52
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (23)	$ (7)

See the Combined Notes to Consolidated Financial Statements

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2020		December 31, 2019	
ASSETS				
Current assets				
Cash and cash equivalents		$ 125		$ 30
Restricted cash and cash equivalents		33		33
Accounts receivable				
Customer accounts receivable	278		244	
Customer allowance for credit losses	(35)		(13)	
Customer accounts receivable, net		243		231
Other accounts receivable	129		98	
Other allowance for credit losses	(13)		(7)	
Other accounts receivable, net		116		91
Receivable from PHI intercompany money pool		117		—
Inventories, net		110		112
Regulatory assets		200		188
Other		13		11
Total current assets		957		696
Property, plant, and equipment (net of accumulated depreciation and amortization of $3,651 and $3,517 as of September 30, 2020 and December 31, 2019, respectively)		7,236		6,909
Deferred debits and other assets				
Regulatory assets		573		584
Investments		113		110
Prepaid pension asset		287		296
Other		61		66
Total deferred debits and other assets		1,034		1,056
Total assets		$ 9,227		$ 8,661

See the Combined Notes to Consolidated Financial Statements

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2020	December 31, 2019
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 82
Long-term debt due within one year	3	2
Accounts payable	206	195
Accrued expenses	144	156
Payables to affiliates	43	66
Customer deposits	54	57
Regulatory liabilities	49	8
Merger related obligation	39	39
Current portion of DC PLUG obligation	30	30
Other	29	22
Total current liabilities	597	657
Long-term debt	3,161	2,862
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,194	1,131
Asset retirement obligations	38	41
Non-pension postretirement benefit obligations	14	20
Regulatory liabilities	647	746
Other	354	297
Total deferred credits and other liabilities	2,247	2,235
Total liabilities	6,005	5,754
Commitments and contingencies		
Shareholder's equity		
Common stock	2,058	1,796
Retained earnings	1,164	1,111
Total shareholder's equity	3,222	2,907
Total liabilities and shareholder's equity	$ 9,227	$ 8,661

See the Combined Notes to Consolidated Financial Statements

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

	Nine Months Ended September 30, 2020		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2019	$ 1,796	$ 1,111	$ 2,907
Net income	—	52	52
Common stock dividends	—	(28)	(28)
Contributions from parent	137	—	137
Balance, March 31, 2020	$ 1,933	$ 1,135	$ 3,068
Net income	—	57	57
Common stock dividends	—	(73)	(73)
Balance, June 30, 2020	$ 1,933	$ 1,119	$ 3,052
Net income	—	118	118
Common stock dividends	—	(73)	(73)
Contributions from parent	125	—	125
Balance, September 30, 2020	$ 2,058	$ 1,164	$ 3,222

	Nine Months Ended September 30, 2019		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2018	$ 1,636	$ 1,104	$ 2,740
Net income	—	55	55
Common stock dividends	—	(24)	(24)
Contributions from parent	14	—	14
Balance, March 31, 2019	$ 1,650	$ 1,135	$ 2,785
Net income	—	64	64
Common stock dividends	—	(48)	(48)
Contributions from parent	115	—	115
Balance, June 30, 2019	$ 1,765	$ 1,151	$ 2,916
Net income	—	98	98
Common stock dividends	—	(101)	(101)
Balance, September 30, 2019	$ 1,765	$ 1,148	$ 2,913

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Operating revenues				
Electric operating revenues	$ 303	$ 304	$ 846	$ 872
Natural gas operating revenues	23	20	116	116
Revenues from alternative revenue programs	8	(6)	(15)	(6)
Operating revenues from affiliates	3	1	7	5
Total operating revenues	337	319	954	987
Operating expenses				
Purchased power	103	105	270	298
Purchased fuel	7	8	49	51
Purchased power from affiliates	21	14	60	50
Operating and maintenance	64	43	160	127
Operating and maintenance from affiliates	37	37	112	113
Depreciation and amortization	48	46	143	138
Taxes other than income taxes	16	15	49	43
Total operating expenses	296	268	843	820
Operating income	41	51	111	167
Other income and (deductions)				
Interest expense, net	(15)	(15)	(47)	(45)
Other, net	2	2	7	10
Total other income and (deductions)	(13)	(13)	(40)	(35)
Income before income taxes	28	38	71	132
Income taxes	1	5	(20)	16
Net income	$ 27	$ 33	$ 91	$ 116
Comprehensive income	$ 27	$ 33	$ 91	$ 116

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Cash flows from operating activities		
Net income	$ 91	$ 116
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	143	138
Deferred income taxes and amortization of investment tax credits	(20)	(2)
Other non-cash operating activities	47	21
Changes in assets and liabilities:		
Accounts receivable	3	29
Receivables from and payables to affiliates, net	(5)	(7)
Inventories	(3)	(7)
Accounts payable and accrued expenses	21	3
Income taxes	(12)	11
Pension and non-pension postretirement benefit contributions	(1)	(1)
Other assets and liabilities	(25)	(22)
Net cash flows provided by operating activities	239	279
Cash flows from investing activities		
Capital expenditures	(278)	(245)
Other investing activities	(3)	1
Net cash flows used in investing activities	(281)	(244)
Cash flows from financing activities		
Changes in short-term borrowings	(56)	57
Issuance of long-term debt	178	—
Retirement of long-term debt	(79)	—
Dividends paid on common stock	(99)	(105)
Contributions from parent	112	—
Other financing activities	(1)	—
Net cash flows provided by (used in) financing activities	55	(48)
Increase (decrease) in cash, cash equivalents, and restricted cash	13	(13)
Cash, cash equivalents, and restricted cash at beginning of period	13	24
Cash, cash equivalents, and restricted cash at end of period	$ 26	$ 11
Supplemental cash flow information		
Increase (decrease) in capital expenditures not paid	$ 8	$ (13)

See the Combined Notes to Consolidated Financial Statements

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2020		December 31, 2019	
ASSETS				
Current assets				
Cash and cash equivalents	$	26	$	13
Accounts receivable				
Customer accounts receivable	141		152	
Customer allowance for credit losses	(22)		(11)	
Customer accounts receivable, net		119		141
Other accounts receivable	53		42	
Other allowance for credit losses	(8)		(4)	
Other accounts receivable, net		45		38
Inventories, net				
Fossil fuel		7		8
Materials and supplies		49		44
Prepaid utility taxes		17		18
Regulatory assets		51		52
Renewable energy credits		4		9
Other		3		2
Total current assets		321		325
Property, plant, and equipment (net of accumulated depreciation and amortization of $1,502 and $1,425 as of September 30, 2020 and December 31, 2019, respectively)		4,209		4,035
Deferred debits and other assets				
Regulatory assets		227		222
Goodwill		8		8
Prepaid pension asset		164		171
Other		63		69
Total deferred debits and other assets		462		470
Total assets	$	4,992	$	4,830

See the Combined Notes to Consolidated Financial Statements

Table of Contents

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2020	December 31, 2019
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 56
Long-term debt due within one year	81	80
Accounts payable	126	112
Accrued expenses	50	46
Payables to affiliates	23	32
Customer deposits	34	36
Regulatory liabilities	46	37
Other	19	15
Total current liabilities	379	414
Long-term debt	1,595	1,487
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	689	655
Asset retirement obligations	14	12
Non-pension postretirement benefits obligations	14	16
Regulatory liabilities	516	574
Other	101	92
Total deferred credits and other liabilities	1,334	1,349
Total liabilities	3,308	3,250
Commitments and contingencies		
Shareholder's equity		
Common stock	1,089	977
Retained earnings	595	603
Total shareholder's equity	1,684	1,580
Total liabilities and shareholder's equity	$ 4,992	$ 4,830

See the Combined Notes to Consolidated Financial Statements

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

	Nine Months Ended September 30, 2020		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2019	$ 977	$ 603	$ 1,580
Net income	—	45	45
Common stock dividends	—	(52)	(52)
Contributions from parent	6	—	6
Balance, March 31, 2020	$ 983	$ 596	$ 1,579
Net income	—	19	19
Common stock dividends	—	(14)	(14)
Contributions from parent	100	—	100
Balance, June 30, 2020	$ 1,083	$ 601	$ 1,684
Net income	—	27	27
Common stock dividends	—	(33)	(33)
Contributions from parent	6	—	6
Balance, September 30, 2020	$ 1,089	$ 595	$ 1,684

	Nine Months Ended September 30, 2019		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2018	$ 914	$ 595	$ 1,509
Net income	—	53	53
Common stock dividends	—	(41)	(41)
Balance, March 31, 2019	$ 914	$ 607	$ 1,521
Net income	—	30	30
Common stock dividends	—	(29)	(29)
Balance, June 30, 2019	$ 914	$ 608	$ 1,522
Net income	—	33	33
Common stock dividends	—	(35)	(35)
Balance, September 30, 2019	$ 914	$ 606	$ 1,520

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Operating revenues				
Electric operating revenues	$ 414	$ 417	$ 969	$ 964
Revenues from alternative revenue programs	5	1	(20)	—
Operating revenues from affiliates	1	1	3	2
Total operating revenues	420	419	952	966
Operating expenses				
Purchased power	207	207	460	463
Purchased power from affiliate	4	3	9	16
Operating and maintenance	45	54	140	142
Operating and maintenance from affiliates	32	32	98	99
Depreciation and amortization	48	43	134	114
Taxes other than income taxes	2	1	6	4
Total operating expenses	338	340	847	838
Gain on sale of assets	—	—	2	—
Operating income	82	79	107	128
Other income and (deductions)				
Interest expense, net	(15)	(15)	(45)	(44)
Other, net	1	1	5	5
Total other income and (deductions)	(14)	(14)	(40)	(39)
Income before income taxes	68	65	67	89
Income taxes	(7)	2	(39)	2
Net income	$ 75	$ 63	$ 106	$ 87
Comprehensive income	$ 75	$ 63	$ 106	$ 87

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Cash flows from operating activities		
Net income	$ 106	$ 87
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	134	114
Deferred income taxes and amortization of investment tax credits	(40)	2
Other non-cash operating activities	34	21
Changes in assets and liabilities:		
Accounts receivable	(62)	(44)
Receivables from and payables to affiliates, net	2	(4)
Inventories	—	(4)
Accounts payable and accrued expenses	16	27
Income taxes	4	5
Pension and non-pension postretirement benefit contributions	(3)	—
Other assets and liabilities	(53)	(18)
Net cash flows provided by operating activities	138	186
Cash flows from investing activities		
Capital expenditures	(281)	(300)
Other investing activities	5	—
Net cash flows used in investing activities	(276)	(300)
Cash flows from financing activities		
Changes in short-term borrowings	(70)	49
Repayments of short-term borrowings with maturities greater than 90 days	—	(125)
Issuance of long-term debt	123	150
Retirement of long-term debt	(38)	(13)
Changes in PHI intercompany money pool	117	—
Dividends paid on common stock	(111)	(100)
Contributions from parent	117	155
Other financing activities	(1)	(1)
Net cash flows provided by financing activities	137	115
(Decrease) increase in cash, cash equivalents, and restricted cash	(1)	1
Cash, cash equivalents, and restricted cash at beginning of period	28	30
Cash, cash equivalents, and restricted cash at end of period	$ 27	$ 31
Supplemental cash flow information		
Increase (decrease) in capital expenditures not paid	$ 9	$ (37)

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2020		December 31, 2019	
ASSETS				
Current assets				
Cash and cash equivalents	$	13	$	12
Restricted cash and cash equivalents		4		2
Accounts receivable				
Customer accounts receivable	165		121	
Customer allowance for credit losses	(32)		(13)	
Customer accounts receivable, net		133		108
Other accounts receivable	65		53	
Other allowance for credit losses	(11)		(5)	
Other accounts receivable, net		54		48
Receivables from affiliates		1		4
Inventories, net		34		34
Prepaid utility taxes		9		—
Regulatory assets		88		57
Other		4		5
Total current assets		340		270
Property, plant, and equipment (net of accumulated depreciation and amortization of $1,276 and $1,210 as of September 30, 2020 and December 31, 2019, respectively)		3,372		3,190
Deferred debits and other assets				
Regulatory assets		395		368
Prepaid pension asset		44		52
Other		50		53
Total deferred debits and other assets		489		473
Total assets[(a)]	$	4,201	$	3,933

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2020	December 31, 2019
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 70
Long-term debt due within one year	261	20
Accounts payable	168	144
Accrued expenses	42	42
Payables to affiliates	24	25
Borrowings from PHI intercompany money pool	117	—
Customer deposits	23	25
Regulatory liabilities	48	25
Other	10	9
Total current liabilities	693	360
Long-term debt	1,156	1,307
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	617	577
Non-pension postretirement benefit obligations	16	17
Regulatory liabilities	279	357
Other	52	39
Total deferred credits and other liabilities	964	990
Total liabilities[(a)]	2,813	2,657
Commitments and contingencies		
Shareholder's equity		
Common stock	1,271	1,154
Retained earnings	117	122
Total shareholder's equity	1,388	1,276
Total liabilities and shareholder's equity	$ 4,201	$ 3,933

(a) ACE's consolidated total assets include $14 million and $17 million at September 30, 2020 and December 31, 2019, respectively, of ACE's consolidated VIE that can only be used to settle the liabilities of the VIE. ACE's consolidated total liabilities include $26 million and $41 million at September 30, 2020 and December 31, 2019, respectively, of ACE's consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 16 — Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

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

	Nine Months Ended September 30, 2020		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2019	$ 1,154	$ 122	$ 1,276
Net income	—	13	13
Common stock dividends	—	(23)	(23)
Contributions from parent	1	—	1
Balance, March 31, 2020	$ 1,155	$ 112	$ 1,267
Net income	—	18	18
Common stock dividends	—	(12)	(12)
Contributions from parent	115	—	115
Balance, June 30, 2020	$ 1,270	$ 118	$ 1,388
Net income	—	75	75
Common stock dividends	—	(76)	(76)
Contributions from parent	1	—	1
Balance, September 30, 2020	$ 1,271	$ 117	$ 1,388

	Nine Months Ended September 30, 2019		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2018	$ 979	$ 147	$ 1,126
Net income	—	10	10
Common stock dividends	—	(12)	(12)
Contributions from parent	5	—	5
Balance, March 31, 2019	$ 984	$ 145	$ 1,129
Net income	—	14	14
Common stock dividends	—	(12)	(12)
Contributions from parent	150	—	150
Balance, June 30, 2019	$ 1,134	$ 147	$ 1,281
Net income	—	63	63
Common stock dividends	—	(76)	(76)
Balance, September 30, 2019	$ 1,134	$ 134	$ 1,268

See the Combined Notes to Consolidated Financial Statements

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

1. Significant Accounting Policies (All Registrants)

Description of Business (All Registrants)

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

Name of Registrant	Business	Service Territories
Exelon Generation Company, LLC	Generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity to both wholesale and retail customers. Generation also sells natural gas, renewable energy, and other energy-related products and services.	Five reportable segments: Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions
Commonwealth Edison Company	Purchase and regulated retail sale of electricity	Northern Illinois, including the City of Chicago
	Transmission and distribution of electricity to retail customers	
PECO Energy Company	Purchase and regulated retail sale of electricity and natural gas	Southeastern Pennsylvania, including the City of Philadelphia (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Pennsylvania counties surrounding the City of Philadelphia (natural gas)
Baltimore Gas and Electric Company	Purchase and regulated retail sale of electricity and natural gas	Central Maryland, including the City of Baltimore (electricity and natural gas)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	
Pepco Holdings LLC	Utility services holding company engaged, through its reportable segments Pepco, DPL, and ACE	Service Territories of Pepco, DPL, and ACE
Potomac Electric Power Company	Purchase and regulated retail sale of electricity	District of Columbia, and major portions of Montgomery and Prince George's Counties, Maryland
	Transmission and distribution of electricity to retail customers	
Delmarva Power & Light Company	Purchase and regulated retail sale of electricity and natural gas	Portions of Delaware and Maryland (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Portions of New Castle County, Delaware (natural gas)
Atlantic City Electric Company	Purchase and regulated retail sale of electricity	Portions of Southern New Jersey
	Transmission and distribution of electricity to retail customers	

Basis of Presentation (All Registrants)

Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology, and supply management services. PHI also has a business services subsidiary, PHISCO, which provides a variety of support services at cost, including legal, accounting, engineering, customer operations, distribution and transmission planning, asset management, system operations, and power procurement, to PHI operating companies. The costs of BSC and PHISCO are directly charged or allocated to the applicable subsidiaries. The results of Exelon's corporate operations are presented as "Other" within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

The accompanying consolidated financial statements as of September 30, 2020 and December 31, 2019 and for the three and nine months ended September 30, 2020 and 2019 are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants' respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2019 Consolidated Balance Sheets were derived from audited financial statements. Financial results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for the fiscal year ending December 31, 2020. These Combined

Notes to Consolidated Financial Statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations.

COVID-19 (All Registrants)

The Registrants have taken steps to mitigate the potential risks posed by the global outbreak (pandemic) of the 2019 novel coronavirus (COVID-19). The Registrants provide a critical service to their customers and have taken measures to keep employees who operate the business safe and minimize unnecessary risk of exposure to the virus, including extra precautions for employees who work in the field. The Registrants have implemented work from home policies where appropriate and imposed travel limitations on employees. In addition, the Registrants have updated their existing business continuity plans.

Management makes estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and accompanying notes, and the amounts of revenues and expenses reported during the periods covered by those financial statements and accompanying notes. Management assessed certain accounting matters that require consideration of forecasted financial information, including, but not limited to, our allowance for credit losses and the carrying value of our goodwill and other long-lived assets, in context with the information reasonably available to us and the unknown future impacts of COVID-19 as of September 30, 2020 and through the date of this report. The Registrants' future assessment of our current expectations of the magnitude and duration of COVID-19, as well as other factors, could result in material impacts to their consolidated financial statements in future reporting periods.

New Accounting Standards (All Registrants)

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

Impairment of Financial Instruments (Issued June 2016). Provides for a new Current Expected Credit Loss (CECL) impairment model for specified financial instruments including loans, trade receivables, debt securities classified as held-to-maturity investments, and net investments in leases recognized by a lessor. Under the new guidance, on initial recognition and at each reporting period, an entity is required to recognize an allowance that reflects its current estimate of credit losses expected to be incurred over the life of the financial instrument based on historical experience, current conditions and reasonable and supportable forecasts. The standard was effective January 1, 2020 and requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption. This standard was primarily applicable to Generation's and the Utility Registrants' Customer accounts receivables balances. This guidance did not have a significant impact on the Registrants’ consolidated financial statements.

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

Allowance for Credit Losses on Accounts Receivables (All Registrants)

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

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

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

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

The Registrants have certain non-customer receivables in Other deferred debits and other assets which primarily are with governmental agencies and other high-quality counterparties with no history of default. As such, the allowance for credit losses related to these receivables is not material. The Registrants monitor these balances and will record an allowance if there are indicators of a decline in credit quality.

2. Regulatory Matters (All Registrants)

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

Utility Regulatory Matters (Exelon and the Utility Registrants)

Distribution Base Rate Case Proceedings

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

Completed Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement (Decrease) Increase	Approved Revenue Requirement (Decrease) Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois (Electric)[(a)]	April 8, 2019	$ (6)	$ (17)	8.91 %	December 4, 2019	January 1, 2020
DPL - Maryland (Electric)	December 5, 2019 (amended April 23, 2020)	17	12	9.60 %	July 14, 2020	July 16, 2020

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

Pending Distribution Base Rate Case Proceedings

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

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement (Decrease) Increase		Requested ROE	Expected Approval Timing
ComEd - Illinois (Electric)[(a)]	April 16, 2020	$	(11)	8.38 %	Fourth quarter of 2020
PECO - Pennsylvania (Natural Gas)	September 30, 2020		69	10.95 %	Second quarter of 2021
BGE - Maryland (Electric and Natural Gas)[(b)]	May 15, 2020 (amended September 11, 2020)		228	10.1 %	Fourth quarter of 2020
Pepco - District of Columbia (Electric)[(c)]	May 30, 2019 (amended June 1, 2020)		136	9.7 %	First quarter of 2021
Pepco - Maryland (Electric)[(d)]	October 26, 2020		110	10.2 %	Second quarter of 2021
DPL - Delaware (Natural Gas)[(e)]	February 21, 2020 (amended October 9, 2020)		7	10.3 %	First quarter of 2021
DPL - Delaware (Electric)[(f)]	March 6, 2020 (amended October 26, 2020)		24	10.3 %	Second quarter of 2021

____
(a) Reflects an increase of $51 million for the initial revenue requirement for 2020 and a decrease of $62 million related to the annual reconciliation for 2019. The revenue requirement for 2020 and annual reconciliation for 2019 provides for a weighted average debt and equity return on distribution rate base of 6.28%, inclusive of an allowed ROE of 8.38%, reflecting the average rate on 30-year treasury notes plus 580 basis points.
(b) Reflects a three-year cumulative multi-year plan for 2021 through 2023 and total requested revenue requirement increases in 2023 of $137 million related to electric distribution and $91 million related to natural gas distribution to recover capital investments made in late 2019 and planned capital investments from 2020 to 2023.
(c) Pepco filed the multi-year plan enhanced proposal as an alternative to address the impacts of COVID-19. Reflects a three-year cumulative multi-year plan for 2020 through 2022 and requested revenue requirement increases of $73 million in 2022 and $63 million in 2023, to recover capital investments made during 2018 through 2020 and planned capital investments through the end of 2022.
(d) Reflects a three-year cumulative multi-year plan for April 1, 2021 through March 31, 2024 and total requested revenue requirement increases of $56 million effective April 1, 2023 and $54 million effective April 1, 2024 to recover capital investments made in 2019 and 2020 and planned capital investments through March 31, 2024.
(e) The rates went into effect on September 21, 2020, subject to refund.
(f) The rates went into effect on October 6, 2020, subject to refund.

Transmission Formula Rates

Transmission Formula Rate (Exelon and the Utility Registrants). ComEd's, PECO's, BGE's, Pepco's, DPL's, and ACE's transmission rates are each established based on a FERC-approved formula. ComEd, BGE, Pepco, DPL, and ACE are required to file an annual update to the FERC-approved formula on or before May 15 and PECO is required to file on or before May 31, with the resulting rates effective on June 1 of the same year. The annual update for ComEd, BGE, DPL, and ACE is based on prior year actual costs and current year projected capital additions (initial year revenue requirement). The annual update for PECO is based on prior year actual costs and current year projected capital additions, accumulated depreciation, and accumulated deferred income taxes. The annual update for Pepco is based on prior year actual costs and current year projected capital additions, accumulated depreciation, depreciation and amortization expense, and accumulated deferred income taxes. The update for ComEd, BGE, DPL, and ACE also reconciles any differences between the revenue requirement in effect beginning June 1 of the prior year and actual costs incurred for that year (annual reconciliation). The update for PECO and Pepco also reconciles any differences between the actual costs and actual revenues for the calendar year (annual reconciliation).

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

For 2020, the following total increases/(decreases) were included in ComEd's, PECO's, BGE's, Pepco's, DPL's, and ACE's electric transmission formula rate filings:

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

____

(a) All rates are effective June 2020, subject to review by interested parties, which is anticipated to be completed by the fourth quarter of 2020 or first quarter of 2021 for ComEd, BGE, Pepco, DPL, and ACE and second quarter of 2021 for PECO.
(b) PECO posted a revised filing to the PJM website on July 17, 2020 reflecting updates to the formula rate based on the FERC order dated July 9, 2020.
(c) The decrease in PECO's transmission revenue requirement relates to refunds from December 1, 2017, in accordance with the settlement agreement dated July 22, 2019. The increase in BGE's transmission revenue requirement includes a $9 million reduction related to a FERC-approved dedicated facilities charge to recover the costs of providing transmission service to specifically designated load by BGE. ComEd, BGE, Pepco, DPL, and ACE's transmission revenue requirement include a decrease related to the April 24, 2020 settlement agreement related to excess deferred income taxes. Refer to Transmission-Related Income Tax Regulatory Assets below for additional information.
(d) Represents the weighted average debt and equity return on transmission rate bases.
(e) 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

Energy Efficiency Formula Rate (Exelon and ComEd). ComEd filed its annual energy efficiency formula rate update with the ICC on May 21, 2020. The filing establishes the revenue requirement used to set the rates that will take effect in January 2021 after the ICC's review and approval. The revenue requirement requested is based on a reconciliation of the 2019 actual costs plus projected 2020 and 2021 expenditures.

Initial Revenue Requirement Increase	Annual Reconciliation Increase	Total Revenue Requirement Increase	Requested Return on Rate Base	Requested ROE
$ 45	$ 3	$ 48 [(a)]	6.28 %	8.38 %

____

(a) The requested revenue requirement increase provides for a weighted average debt and equity return on rate base of 6.28% inclusive of an allowed ROE of 8.38%. The ROE reflects the average rate on 30-year treasury notes plus 580 basis points. The ROE applicable to the 2019 reconciliation year is 8.96% and the return on rate base is 6.56%, which includes a performance adjustment that can either increase or decrease the ROE.

New Jersey Regulatory Matters

Advanced Metering Infrastructure Filing (Exelon, PHI, and ACE). On August 26, 2020, ACE filed an application with the NJBPU as was required seeking approval to deploy a smart energy network in alignment with New Jersey's Energy Master Plan and Clean Energy Act. The proposal consists of estimated costs totaling $220 million, with deployment taking place over a 3-year implementation period from approximately 2021 to 2024 that involves the installation of an integrated system of smart meters for all customers accompanied by the requisite communications facilities and data management systems. ACE is seeking authority to recover these estimated investments through a combination of the ACE Infrastructure Investment Program rider mechanism and future distribution base rates. ACE currently expects a decision in this matter in the third quarter of 2021 but cannot predict if the NJBPU will approve the application as filed.

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 asset for the portion of the income tax regulatory asset that would have been previously amortized.

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

On September 7, 2018, FERC issued orders rejecting 1) BGE's rehearing request of FERC's November 16, 2017 order; and 2) 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 Court of Appeals for the D.C. Circuit. On March 27, 2020, the Court of Appeals denied BGE's November 2, 2018 appeal.

On October 1, 2018, ComEd, BGE, Pepco, DPL, and ACE submitted filings to recover only ongoing non-TCJA amortization amounts and credit TCJA transmission-related income tax regulatory liabilities to customers for the prospective period starting on October 1, 2018. On April 26, 2019, FERC issued an order accepting ComEd's, BGE's, Pepco's, DPL's, and ACE's October 1, 2018 filings, effective October 1, 2018, subject to refund and established hearing and settlement judge procedures. On April 24, 2020, ComEd, BGE, Pepco, DPL, ACE, and other parties filed a settlement agreement with FERC, 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

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

ComEd. Regulatory assets increased $255 million primarily due to an increase of $145 million in the Energy Efficiency Costs regulatory asset, $58 million in the Electric Distribution Formula Rate Significant One-time Events regulatory asset, $47 million in the ARO regulatory asset, and $18 million in the COVID-19 regulatory asset recorded in 2020, partially offset by a decrease of $37 million in the Electric Distribution Formula Rate Annual Reconciliations regulatory asset. Refer to COVID-19 disclosure below for additional information.

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

PECO. Regulatory assets increased $135 million primarily due to an increase of $119 million in the Deferred Income Taxes regulatory asset and $20 million in new COVID-19 regulatory asset recorded in the third quarter of 2020. Refer to COVID-19 disclosure below for additional information.

BGE. Regulatory liabilities decreased $68 million primarily due to a decrease of $73 million in the Deferred Income Taxes regulatory liability.

Pepco. Regulatory liabilities decreased $58 million primarily due to a decrease of $99 million in the Deferred Income Taxes regulatory liability, partially offset by a $24 million increase in the Transmission FERC Formula Rate regulatory liability, and $24 million in the Electric Energy and Natural Gas Costs regulatory liability.

DPL. Regulatory liabilities decreased $49 million primarily due to a decrease of $54 million in the Deferred Income Taxes regulatory liability, $4 million in the Removal Costs regulatory liability, and $3 million in the Electric Energy and Natural Gas Costs regulatory liability, partially offset by a $16 million increase in the Transmission FERC Formula Rate regulatory liability.

ACE. Regulatory assets increased $58 million primarily due to an increase of $29 million in the Deferred Storm Costs regulatory asset, $19 million in the Uncollectible Deferral regulatory asset, and $17 million in the Electric Energy Costs regulatory asset, partially offset by a decrease of $9 million in the Securitized Stranded Costs regulatory asset. Regulatory liabilities decreased $55 million primarily due to a decrease of $80 million in the Deferred Income Taxes regulatory liability, partially offset by a $13 million increase in Transmission FERC Formula Rate regulatory liability, and $9 million in Stranded Costs regulatory liability.

COVID-19 (Exelon and the Utility Registrants). Starting in March of 2020, the Utility Registrants temporarily suspended customer disconnections for non-payment and temporarily ceased new late payment fees for all customers and restored service to customers upon request who were disconnected in the last twelve months. The duration and extent of these measures varies by jurisdiction. While these measures are no longer in place for some jurisdictions, they are expected to continue through the first quarter of 2021 in other jurisdictions. Typically, the Utility Registrants recover credit loss expense through rate required programs or distribution base rate cases. ComEd and ACE have existing mechanisms for recovery of credit loss expense. For those jurisdictions without an existing rate required program to recover credit loss expense, the Utility Registrants are pursuing strategies to recover incremental costs being incurred as a result of COVID-19:

- In the period of April to July of 2020, the MDPSC, the DCPSC, the DPSC, and the NJBPU issued orders authorizing the creation of regulatory assets to track incremental COVID-19 related costs.
- In May of 2020, the PAPUC issued a Secretarial Letter authorizing the creation of regulatory assets to track incremental credit loss expense related to COVID-19.

The Utility Registrants have also incurred direct costs related to COVID-19 consisting primarily of costs to acquire personal protective equipment, costs for cleaning supplies and services, and costs to hire healthcare professionals to monitor the health of their employees.

The Utility Registrants have recorded regulatory assets for the impacts of COVID-19 reflecting primarily incremental credit losses and direct costs, partially offset by a decrease in travel costs at BGE and PHI. The Utility Registrants expect to seek recovery in upcoming distribution base rate cases. Exelon and the Utility Registrants recorded the following regulatory assets related to COVID-19:

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
September 30, 2020	$ 60	$ 18	$ 20	$ 11	$ 11	$ 8	$ 3	$ —

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

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

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

	Exelon	ComEd[(a)]	PECO	BGE[(b)]	PHI	Pepco[(c)]	DPL[(c)]	ACE
September 30, 2020	$ 54	$ —	$ —	$ 47	$ 7	$ 4	$ 3	$ —
December 31, 2019	63	3	—	53	7	4	3	—

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

Generation Regulatory Matters (Exelon and Generation)

New Jersey Regulatory Matters

New Jersey Clean Energy Legislation. On May 23, 2018, New Jersey enacted legislation that established a ZEC program that provides compensation for nuclear plants that demonstrate to the NJBPU that they meet certain requirements, including that they make a significant contribution to air quality in the state and that their revenues are insufficient to cover their costs and risks. Under the legislation, the NJBPU will issue ZECs to qualifying nuclear power plants and the electric distribution utilities in New Jersey, including ACE, will be required to purchase those ZECs. On April 18, 2019, the NJBPU approved the award of ZECs to Salem 1 and Salem 2. Upon approval, Generation began recognizing revenue for the sale of New Jersey ZECs in the month they are generated and has recognized $56 million and $31 million for the nine months ended September 30, 2020 and 2019, respectively. On May 15, 2019, New Jersey Rate Counsel appealed the NJBPU's decision to the New Jersey Superior Court. Briefing has been completed and oral argument is scheduled for December 9, 2020. Exelon and Generation cannot predict the outcome of the appeal. See Note 6 — Early Plant Retirements for additional information related to Salem.

New York Regulatory Matters

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

On November 30, 2016 (as amended on January 13, 2017), a group of parties filed a Petition in New York State court seeking to invalidate the ZEC program, which argued that the NYPSC did not have authority to establish the program, that it violated state environmental law and that it violated certain technical provisions of the State Administrative Procedures Act when adopting the ZEC program. On January 22, 2018, the court dismissed the environmental claims and the majority of the plaintiffs from the case but denied the motions to dismiss with respect to the remaining five plaintiffs and claims, without commenting on the merits of the case. On October 8, 2019, the court dismissed all remaining claims. The petitioners filed a notice of appeal on November 4, 2019 and originally had until May 4, 2020 to file their brief. Due to COVID-19 related restrictions, the court extended the deadline to July 29, 2020. Petitioners did not file a brief by the deadline, so the case is deemed dismissed. Petitioners are permitted up to one year from July 29, 2020 to file a motion to vacate the dismissal if they can show good cause for the delay.

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

New England Regulatory Matters

Mystic Units 8 & 9 and Everett Marine Terminal Cost of Service Agreement (Exelon and Generation). On March 29, 2018, Generation notified grid operator ISO-NE of its plans to early retire Mystic Units 8 and 9 absent regulatory reforms on June 1, 2022. On May 16, 2018, Generation made a filing with FERC to establish cost-of-service compensation and terms and conditions of service for Mystic Units 8 & 9 for the period between June 1, 2022 - May 31, 2024. On December 20, 2018, FERC issued an order accepting the cost of service compensation, reflecting a number of adjustments to the annual fixed revenue requirement and allowing for recovery of a substantial portion of the costs associated with the adjacent Everett Marine Terminal acquired by

Generation in October 2018. Those adjustments were reflected in a compliance filing made on March 1, 2019. In the December 20, 2018 order, FERC also directed a paper hearing on ROE using a new methodology. On January 22, 2019, Exelon and several other parties filed requests for rehearing of certain findings in the order.

On July 17, 2020, FERC issued three orders, which together affirmed the recovery of key elements of Mystic's cost of service compensation, including recovery of costs associated with the operation of the Everett Marine Terminal. FERC directed a downward adjustment to the rate base for Mystic Units 8 and 9, the effect of which will be partially offset by elimination of a crediting mechanism for third party gas sales during the term of the cost of service agreement. A compliance filing was submitted on September 15, 2020. Several parties filed protests to the compliance filing on the issue of how gross plant in-service was calculated, and Generation filed an answer to the protests on October 21, 2020. On July 28, 2020, FERC ordered additional briefings in the ROE proceeding.

On August 25, 2020, a group of New England generators filed a complaint against Generation seeking to extend the scope of the claw back provision in the cost-of-service agreement, whereby Generation would refund certain amounts recovered during the term of the cost of service if it returns to market afterwards. On September 14, 2020, Generation filed an answer to the complaint arguing that the complaint is procedurally improper and a collateral attack on existing FERC orders and pointing out that the ISO-NE tariff contains protections against the New England generators' concerns that they failed to mention. Generation cannot predict the outcome of this proceeding.

On June 10, 2020, Generation filed a complaint with FERC against ISO-NE on the grounds that ISO-NE failed to follow its tariff with respect to its evaluation of Mystic for transmission security for the 2024 to 2025 Capacity Commitment Period (FCA 15) and that the modifications that ISO-NE made to its unfiled planning procedures to avoid retaining Mystic should have been filed with FERC for approval. On July 27, 2020, ISO-NE issued a memo to NEPOOL announcing its determination pursuant to its unfiled planning procedures that Mystic Units 8 and 9 are not needed for FCA 15 for transmission security. It had previously determined Mystic Units 8 and 9 are not needed for fuel security. On August 17, 2020, FERC issued an order denying the complaint. On September 16, 2020, Generation filed a request for rehearing with FERC. The timing and the outcome of this proceeding is uncertain.

See Note 6 — Early Plant Retirements and Note 8 — Asset Impairments for additional information on the impacts of Generation's August 2020 decision to retire Mystic Units 8 & 9 upon expiration of the cost of service agreement.

Federal Regulatory Matters

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

For Generation's facilities in PJM and NYISO that are currently receiving ZEC compensation, an expanded MOPR would require exclusion of ZEC compensation when bidding into future capacity auctions, resulting in an increased risk of these facilities not receiving capacity revenues in future auctions.

On December 19, 2019, FERC required PJM to broadly apply the MOPR to all new and existing resources including nuclear, renewables, demand response, energy efficiency, storage, and all resources owned by vertically-integrated utilities. This greatly expands the breadth and scope of PJM's MOPR, which is effective as of PJM's next capacity auction. While FERC included some limited exemptions, no exemptions were available to state-supported nuclear resources.

FERC provided no new mechanism for accommodating state-supported resources other than the existing FRR mechanism (under which an entire utility zone would be removed from PJM's capacity auction along with sufficient resources to support the load in such zone). In response to FERC's order, PJM submitted a compliance filing on March 18, 2020 wherein PJM proposed tariff language interpreting and implementing FERC's directives and proposed a schedule for resuming capacity auctions that is contingent on the timing of FERC's action on the compliance filing.

On April 16, 2020, FERC issued an order largely denying most requests for rehearing of FERC's December 2019 order but granting a few clarifications that required an additional PJM compliance filing which PJM submitted on June 1, 2020.

On October 15, 2020, FERC issued an order denying requests for rehearing of its April 16, 2020 order and accepted PJM's two compliance filings, subject to a further compliance filing to revise minor aspects of the proposed MOPR methodology. As part of that order, FERC also accepted PJM's proposal to condense the schedule of activities leading up to the next capacity auction but did not specify when that schedule would commence given that a key element of the MOPR level computation remains pending before FERC in another proceeding.

FERC issued an order on May 21, 2020 involving reforms to PJM's day-ahead and real-time reserves markets that need to be reflected in the calculation of MOPR levels. In approving reforms to PJM's reserves markets, FERC also directed PJM to develop a new methodology for estimating revenues that resources will receive for sales of energy and related services (referred to as the Energy and Ancillary Services Offset) and to use that new methodology in calculating a number of parameters and assumptions used in the capacity market, including MOPR levels. PJM submitted all elements of its new Energy and Ancillary Services Offset revenue projection methodology on August 5, 2020. On review of this compliance filing, FERC is expected to address how these additional reforms will impact MOPR levels, the timeline for implementing the new revenue projection methodology, and the timing for commencing the capacity auction schedule.

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

Exelon is currently working with PJM and other stakeholders to pursue the FRR option as an alternative to the PJM capacity auction. If Illinois implements the FRR option, Generation's Illinois nuclear plants could be removed from PJM's capacity auction and instead supply capacity and be compensated under the FRR program, which has the potential to mitigate the current economic distress being experienced by Generation's nuclear plants in Illinois, as discussed in Note 6 - Early Plant Retirements. Implementing the FRR program in Illinois will require both legislative and regulatory changes. Whether legislation is needed in New Jersey would depend on how the state chooses to structure an FRR program. Exelon cannot predict whether or when such legislative and regulatory changes can be implemented.

On February 20, 2020, FERC issued an order rejecting requests to expand NYISO's version of the MOPR (referred to as buyer-side mitigation rules) beyond its current limited applicability to certain resources in downstate. However, on October 14, 2020, two natural gas-fired generators in New York filed a complaint at FERC seeking to expand the MOPR in NYISO to apply to all resources, new and existing, across the entire NYISO market. Exelon plans to strenuously oppose expansion of FERC's MOPR policies in the NYISO market. While it is too early in the proceeding to predict its outcome, if FERC follows its MOPR precedent in PJM and applies the MOPR in NYISO broadly as requested in the complaint, Generation's facilities in NYISO that are receiving ZEC compensation may be at increased risk of not clearing the capacity auction.

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

Operating License Renewals

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

On October 29, 2019, Generation and MDE filed with FERC a Joint Offer of Settlement (Offer of Settlement) that would resolve all outstanding issues relating to the 401 Certification. Pursuant to the Offer of Settlement, the parties submitted Proposed License Articles to FERC to be incorporated by FERC into the new license in accordance with FERC's discretionary authority under the Federal Power Act. Among the Proposed License Articles are modifications to river flows to improve aquatic habitat, eel passage improvements, and initiatives to support rare, threatened and endangered wildlife. If FERC approves the Offer of Settlement and incorporates the Proposed License Articles into the new license without modification, then MDE would waive its rights to issue a 401 Certification and Generation would agree, pursuant to a separate agreement with MDE (MDE Settlement), to implement additional environmental protection, mitigation, and enhancement measures over the anticipated 50-year term of the new license. These measures address mussel restoration and other ecological and water quality matters, among other commitments. Exelon's commitments under the various provisions of the Offer of Settlement and MDE Settlement are not effective unless and until FERC approves the Offer of Settlement and issues the new license with the Proposed License Articles. Generation cannot currently predict when FERC will issue the new license.

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

3. Revenue from Contracts with Customers (All Registrants)

The Registrants recognize revenue from contracts with customers to depict the transfer of goods or services to customers at an amount that the entities expect to be entitled to in exchange for those goods or services. Generation's primary sources of revenue include competitive sales of power, natural gas, and other energy-related products and services. The Utility Registrants' primary sources of revenue include regulated electric and gas tariff sales, distribution, and transmission services.

See Note 4 — Revenue from Contracts with Customers of the Exelon 2019 Form 10-K for additional information regarding the primary sources of revenue for the Registrants.

Contract Balances (All Registrants)

Contract Assets

Generation records contract assets for the revenue recognized on the construction and installation of energy efficiency assets and new power generating facilities before Generation has an unconditional right to bill for and receive the consideration from the customer. These contract assets are subsequently reclassified to receivables when the right to payment becomes unconditional. Generation records contract assets and contract receivables within Other current assets and Customer accounts receivable, net, respectively, within Exelon's and Generation's Consolidated Balance Sheets.

The following table provides a rollforward of the contract assets reflected in Exelon's and Generation's Consolidated Balance Sheets for the three and nine months ended September 30, 2020 and 2019. The Utility Registrants do not have any contract assets.

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

	Exelon	Generation
Balance as of December 31, 2019	$ 174	$ 174
Amounts reclassified to receivables	(19)	(19)
Revenues recognized	17	17
Balance at March 31, 2020	$ 172	$ 172
Amounts reclassified to receivables	(26)	(26)
Revenues recognized	13	13
Balance at June 30, 2020	$ 159	$ 159
Amounts reclassified to receivables	(18)	(18)
Revenues recognized	19	19
Balance at September 30, 2020	$ 160	$ 160

	Exelon	Generation
Balance as of December 31, 2018	$ 187	$ 187
Amounts reclassified to receivables	(26)	(26)
Revenues recognized	26	26
Balance at March 31, 2019	$ 187	$ 187
Amounts reclassified to receivables	(18)	(18)
Revenues recognized	27	27
Balance at June 30, 2019	$ 196	$ 196
Amounts reclassified to receivables	(65)	(65)
Revenues recognized	39	39
Balance at September 30, 2019	$ 170	$ 170

Contract Liabilities

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

For Generation, these contract liabilities primarily relate to upfront consideration received or due for equipment service plans, solar panel leases, and the Illinois ZEC program that introduces a cap on the total consideration to be received by Generation.

On July 1, 2020, Pepco, DPL, and ACE each entered into a collaborative arrangement with an unrelated owner and manager of communication infrastructure (the Buyer). Under this arrangement, Pepco, DPL, and ACE sold a 60% undivided interest in their respective portfolios of transmission tower attachment agreements with telecommunications companies to the Buyer, in addition to transitioning management of the day-to-day operations of the jointly-owned agreements to the Buyer for 35 years, while retaining the safe and reliable operation of its utility assets. In return, Pepco, DPL, and ACE will provide the Buyer limited access on the portion of the towers where the equipment resides for the purposes of managing the agreements for the benefit of Pepco, DPL, ACE, and the Buyer. In addition, for an initial period of three years and two, two-year extensions that are subject to certain conditions, the Buyer has the exclusive right to enter into new agreements with telecommunications companies and to receive a 30% undivided interest in those new agreements. PHI, Pepco, DPL, and ACE received cash and recorded contract liabilities as of July 1, 2020 as shown in the table below. The revenue attributable to this arrangement will be recognized as operating revenue over the 35 years under the collaborative arrangement.

The following table provides a rollforward of the contract liabilities reflected in Exelon's, Generation's, PHI's, Pepco's, DPL's, and ACE'S Consolidated Balance Sheets for the three and nine months ended September 30, 2020 and 2019. As of September 30, 2020 and December 31, 2019, ComEd's, PECO's, and BGE's contract liabilities were immaterial.

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

	Exelon	Generation	PHI	Pepco	DPL	ACE
Balance as of December 31, 2019	$ 33	$ 71	$ —	$ —	$ —	$ —
Consideration received or due	20	55	—	—	—	—
Revenues recognized	(24)	(70)	—	—	—	—
Balance at March 31, 2020	$ 29	$ 56	$ —	$ —	$ —	$ —
Consideration received or due	13	34	—	—	—	—
Revenues recognized	(22)	(63)	—	—	—	—
Balance at June 30, 2020	$ 20	$ 27	$ —	$ —	$ —	$ —
Consideration received or due	154	94	124	98	13	13
Revenues recognized	(25)	(65)	(2)	(2)	—	—
Balance at September 30, 2020	$ 149	$ 56	$ 122	$ 96	$ 13	$ 13

	Exelon	Generation	PHI	Pepco	DPL	ACE
Balance as of December 31, 2018	$ 27	$ 42	$ —	$ —	$ —	$ —
Consideration received or due	21	63	—	—	—	—
Revenues recognized	(23)	(66)	—	—	—	—
Balance at March 31, 2019	$ 25	$ 39	$ —	$ —	$ —	$ —
Consideration received or due	17	52	—	—	—	—
Revenues recognized	(21)	(65)	—	—	—	—
Balance at June 30, 2019	$ 21	$ 26	$ —	$ —	$ —	$ —
Consideration received or due	27	83	—	—	—	—
Revenues recognized	(22)	(61)	—	—	—	—
Balance at September 30, 2019	$ 26	$ 48	$ —	$ —	$ —	$ —

The following table reflects revenues recognized in the three and nine months ended September 30, 2020 and 2019, which were included in contract liabilities at December 31, 2019 and 2018, respectively:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Exelon	$ 2	$ 3	$ 25	$ 17
Generation	2	3	63	32

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 September 30, 2020. This disclosure only includes contracts for which the total consideration is fixed and determinable at contract inception. The average contract term varies by customer type and commodity but ranges from one month to several years.

This disclosure excludes Generation's power and gas sales contracts as they contain variable volumes and/or variable pricing. This disclosure also excludes the Utility Registrants' gas and electric tariff sales contracts and transmission revenue contracts as they generally have an original expected duration of one year or less and, therefore, do not contain any future, unsatisfied performance obligations to be included in this disclosure.

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

	2020	2021	2022	2023	2024 and thereafter	Total
Exelon	$ 92	$ 223	$ 93	$ 53	$ 370	$ 831
Generation	136	313	123	53	275	900
PHI	2	9	8	8	95	122
Pepco	2	7	6	6	75	96
DPL	—	1	1	1	10	13
ACE	—	1	1	1	10	13

Revenue Disaggregation (All Registrants)

The Registrants disaggregate revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. See Note 4 — Segment Information for the presentation of the Registrant's revenue disaggregation.

4. Segment Information (All Registrants)

Operating segments for each of the Registrants are determined based on information used by the CODM in deciding how to evaluate performance and allocate resources at each of the Registrants.

Exelon has eleven reportable segments, which include Generation's five reportable segments consisting of the Mid-Atlantic, Midwest, New York, ERCOT, and all other power regions referred to collectively as “Other Power Regions” and ComEd, PECO, BGE, and PHI's three reportable segments consisting of Pepco, DPL, and ACE. ComEd, PECO, BGE, Pepco, DPL, and ACE each represent a single reportable segment, and as such, no separate segment information is provided for these Registrants. Exelon, ComEd, PECO, BGE, Pepco, DPL, and ACE's CODMs evaluate the performance of and allocate resources to ComEd, PECO, BGE, Pepco, DPL, and ACE based on net income.

The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned to these same geographic regions. Descriptions of each of Generation’s five reportable segments are as follows:

- **Mid-Atlantic** represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia, and parts of Pennsylvania and North Carolina.
- **Midwest** represents operations in the western half of PJM and the United States footprint of MISO, excluding MISO’s Southern Region.
- **New York** represents operations within NYISO.
- **ERCOT** represents operations within Electric Reliability Council of Texas.
- **Other Power Regions:**
  - **New England** represents the operations within ISO-NE.
  - **South** represents operations in the FRCC, MISO’s Southern Region, and the remaining portions of the SERC not included within MISO or PJM.
  - **West** represents operations in the WECC, which includes California ISO.
  - **Canada** represents operations across the entire country of Canada and includes AESO, OIESO, and the Canadian portion of MISO.

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

The CODMs for Exelon and Generation evaluate the performance of Generation's electric business activities and allocate resources based on RNF. Generation believes that RNF is a useful measurement of operational performance. RNF is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and affiliated sales to the Utility Registrants. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy, and ancillary services. Fuel expense includes the fuel costs for Generation's owned generation and fuel costs associated with tolling agreements. The results of Generation's other business activities are not regularly reviewed by the CODM and are therefore not classified as operating segments or included in the regional reportable segment amounts. These activities include natural gas, as well as other miscellaneous business activities that are not significant to Generation's overall operating revenues or results of operations. Further, Generation's unrealized mark-to-market gains and losses on economic hedging activities and its amortization of certain intangible assets and liabilities relating to commodity contracts recorded at fair value from mergers and acquisitions are also excluded from the regional reportable segment amounts. Exelon and Generation do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the three and nine months ended September 30, 2020 and 2019 is as follows:

Three Months Ended September 30, 2020 and 2019

	Generation	ComEd	PECO	BGE	PHI	Other[a]	Intersegment Eliminations	Exelon
Operating revenues[b]:								
2020								
Competitive businesses electric revenues	$ 4,201	$ —	$ —	$ —	$ —	$ —	$ (326)	$ 3,875
Competitive businesses natural gas revenues	323	—	—	—	—	—	—	323
Competitive businesses other revenues	135	—	—	—	—	—	(3)	132
Rate-regulated electric revenues	—	1,643	759	646	1,339	—	(22)	4,365
Rate-regulated natural gas revenues	—	—	54	85	23	—	(3)	159
Shared service and other revenues	—	—	—	—	6	484	(491)	(1)
Total operating revenues	$ 4,659	$ 1,643	$ 813	$ 731	$ 1,368	$ 484	$ (845)	$ 8,853
2019								
Competitive businesses electric revenues	$ 4,314	$ —	$ —	$ —	$ —	$ —	$ (275)	$ 4,039
Competitive businesses natural gas revenues	265	—	—	—	—	—	1	266
Competitive businesses other revenues	195	—	—	—	—	—	(1)	194
Rate-regulated electric revenues	—	1,583	716	619	1,357	—	(7)	4,268
Rate-regulated natural gas revenues	—	—	62	84	20	—	(3)	163
Shared service and other revenues	—	—	—	—	3	474	(478)	(1)
Total operating revenues	$ 4,774	$ 1,583	$ 778	$ 703	$ 1,380	$ 474	$ (763)	$ 8,929

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

	Generation	ComEd	PECO	BGE	PHI	Other[(a)]	Intersegment Eliminations	Exelon
Intersegment revenues[(c)]:								
2020	$ 331	$ 15	$ 3	$ 6	$ 6	$ 485	$ (845)	$ 1
2019	275	4	1	6	4	474	(764)	—
Depreciation and amortization:								
2020	$ 558	$ 294	$ 85	$ 133	$ 200	$ 19	$ —	$ 1,289
2019	407	259	83	116	193	25	—	1,083
Operating expenses:								
2020	$ 4,727	$ 1,302	$ 658	$ 642	$ 1,102	$ 489	$ (833)	$ 8,087
2019	4,274	1,256	595	612	1,124	457	(759)	7,559
Interest expense, net:								
2020	$ 80	$ 95	$ 39	$ 34	$ 67	$ 89	$ —	$ 404
2019	109	91	33	31	66	79	—	409
Income (loss) before income taxes:								
2020	$ 219	$ 256	$ 122	$ 61	$ 215	$ (87)	$ —	$ 786
2019	501	245	154	67	203	(68)	—	1,102
Income Taxes:								
2020	$ 100	$ 60	$ (16)	$ 8	$ (1)	$ 65	$ —	$ 216
2019	87	45	14	12	14	—	—	172
Net income (loss):								
2020	$ 117	$ 196	$ 138	$ 53	$ 216	$ (151)	$ —	$ 569
2019	244	200	140	55	189	(68)	—	760
Capital Expenditures:								
2020	$ 282	$ 554	$ 312	$ 290	$ 386	$ 9	$ —	$ 1,833
2019	392	452	228	300	308	7	—	1,687

____

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

(b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 17 — Supplemental Financial Information for additional information on total utility taxes.

(c) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in Operating revenues in the Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Related Party Transactions for additional information on intersegment revenues.

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

PHI:

	Pepco	DPL	ACE	Other[(a)]	Intersegment Eliminations	PHI
Operating revenues[(b)]:						
2020						
Rate-regulated electric revenues	$ 611	$ 314	$ 420	$ —	$ (6)	$ 1,339
Rate-regulated natural gas revenues	—	23	—	—	—	23
Shared service and other revenues	—	—	—	91	(85)	6
Total operating revenues	$ 611	$ 337	$ 420	$ 91	$ (91)	$ 1,368
2019						
Rate-regulated electric revenues	$ 642	$ 299	$ 419	$ —	$ (3)	$ 1,357
Rate-regulated natural gas revenues	—	20	—	—	—	20
Shared service and other revenues	—	—	—	92	(89)	3
Total operating revenues	$ 642	$ 319	$ 419	$ 92	$ (92)	$ 1,380
Intersegment revenues[(c)]:						
2020	$ 3	$ 3	$ 1	$ 90	$ (91)	$ 6
2019	2	1	1	93	(93)	4
Depreciation and amortization:						
2020	$ 96	$ 48	$ 48	$ 8	$ —	$ 200
2019	95	46	43	9	—	193
Operating expenses:						
2020	$ 465	$ 296	$ 338	$ 94	$ (91)	$ 1,102
2019	515	268	340	95	(94)	1,124
Interest expense, net:						
2020	$ 35	$ 15	$ 15	$ 2	$ —	$ 67
2019	33	15	15	3	—	66
Income (loss) before income taxes:						
2020	$ 121	$ 28	$ 68	$ (2)	$ —	$ 215
2019[(d)]	103	38	65	(3)	—	203
Income Taxes:						
2020	$ 3	$ 1	$ (7)	$ 2	$ —	$ (1)
2019	5	5	2	2	—	14
Net income (loss):						
2020	$ 118	$ 27	$ 75	$ (4)	$ —	$ 216
2019	98	33	63	(5)	—	189
Capital Expenditures:						
2020	$ 188	$ 94	$ 103	$ 1	$ —	$ 386
2019	157	85	73	(7)	—	308

____
(a) Other primarily includes PHI's corporate operations, shared service entities, and other financing and investment activities.
(b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 17 — Supplemental Financial Information for additional information on total utility taxes.
(c) Includes intersegment revenues with ComEd, BGE, and PECO, which are eliminated at Exelon.
(d) The Income (loss) before income taxes amounts in Other and Intersegment Eliminations have been adjusted by an offsetting $195 million for consistency with the Exelon consolidating disclosure above.

The following tables disaggregate the Registrants' revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. For Generation, the disaggregation of revenues reflects Generation's two primary products of power sales and natural gas sales, with further disaggregation of power sales provided by geographic region. For the Utility Registrants, the disaggregation of revenues reflects the two primary utility services of rate-regulated electric sales and rate-regulated natural gas sales (where applicable), with further disaggregation of these tariff sales provided by major customer groups. Exelon's disaggregated revenues are consistent with Generation and the Utility Registrants, but exclude any intercompany revenues.

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

Competitive Business Revenues (Generation):

	Three Months Ended September 30, 2020				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 1,327	$ (20)	$ 1,307	$ 6	$ 1,313
Midwest	974	68	1,042	1	1,043
New York	401	5	406	—	406
ERCOT	249	74	323	7	330
Other Power Regions	937	186	1,123	(14)	1,109
Total Competitive Businesses Electric Revenues	3,888	313	4,201	—	4,201
Competitive Businesses Natural Gas Revenues	169	154	323	—	323
Competitive Businesses Other Revenues[c]	85	50	135	—	135
Total Generation Consolidated Operating Revenues	$ 4,142	$ 517	$ 4,659	$ —	$ 4,659

	Three Months Ended September 30, 2019				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 1,351	$ 10	$ 1,361	$ 3	$ 1,364
Midwest	1,052	47	1,099	(17)	1,082
New York	414	15	429	—	429
ERCOT	288	72	360	5	365
Other Power Regions	873	192	1,065	(25)	1,040
Total Competitive Businesses Electric Revenues	3,978	336	4,314	(34)	4,280
Competitive Businesses Natural Gas Revenues	160	105	265	34	299
Competitive Businesses Other Revenues[c]	112	83	195	—	195
Total Generation Consolidated Operating Revenues	$ 4,250	$ 524	$ 4,774	$ —	$ 4,774

____
(a) Includes all wholesale and retail electric sales to third parties and affiliated sales to the Utility Registrants.
(b) Includes revenues from derivatives and leases.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Includes unrealized mark-to-market gains of $37 million and $77 million in 2020 and 2019, respectively, and the elimination of intersegment revenues.

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

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

	Three Months Ended September 30, 2020			Three Months Ended September 30, 2019		
	RNF from external customers[(a)]	Intersegment RNF	Total RNF	RNF from external customers[(a)]	Intersegment RNF	Total RNF
Mid-Atlantic	$ 586	$ 5	$ 591	$ 684	$ 5	$ 689
Midwest	748	2	750	763	(16)	747
New York	281	4	285	288	3	291
ERCOT	141	6	147	76	(4)	72
Other Power Regions	253	(28)	225	212	(28)	184
Total Revenues net of purchased power and fuel expense for Reportable Segments	2,009	(11)	1,998	2,023	(40)	1,983
Other[(b)]	336	11	347	100	40	140
Total Generation Revenues net of purchased power and fuel expense	$ 2,345	$ —	$ 2,345	$ 2,123	$ —	$ 2,123

____

(a) Includes purchases and sales from/to third parties and affiliated sales to the Utility Registrants.

(b) Other represents activities not allocated to a region. See text above for a description of included activities. Includes unrealized mark-to-market gains of $255 million and $17 million in 2020 and 2019, respectively, accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 6 - Early Plant Retirements of $24 million, which includes an impairment charge of $10 million, and $3 million decrease to revenue net of purchased power and fuel expense in 2020 and 2019, respectively, and the elimination of intersegment RNF.

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

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

	Three Months Ended September 30, 2020						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$ 920	$ 518	$ 389	$ 763	$ 307	$ 193	$ 263
Small commercial & industrial	379	104	65	134	36	45	53
Large commercial & industrial	135	66	113	262	195	21	46
Public authorities & electric railroads	10	7	7	14	8	3	3
Other[a]	234	58	78	141	47	44	50
Total rate-regulated electric revenues[b]	$ 1,678	$ 753	$ 652	$ 1,314	$ 593	$ 306	$ 415
Rate-regulated natural gas revenues							
Residential	$ —	$ 32	$ 55	$ 11	$ —	$ 11	$ —
Small commercial & industrial	—	16	9	6	—	6	—
Large commercial & industrial	—	—	21	1	—	1	—
Transportation	—	6	—	3	—	3	—
Other[c]	—	1	3	2	—	2	—
Total rate-regulated natural gas revenues[d]	$ —	$ 55	$ 88	$ 23	$ —	$ 23	$ —
Total rate-regulated revenues from contracts with customers	$ 1,678	$ 808	$ 740	$ 1,337	$ 593	$ 329	$ 415
Other revenues							
Revenues from alternative revenue programs	$ (38)	$ 5	$ (9)	$ 31	$ 18	$ 8	$ 5
Other rate-regulated electric revenues[e]	3	—	—	—	—	—	—
Other rate-regulated natural gas revenues[e]	—	—	—	—	—	—	—
Total other revenues	$ (35)	$ 5	$ (9)	$ 31	$ 18	$ 8	$ 5
Total rate-regulated revenues for reportable segments	$ 1,643	$ 813	$ 731	$ 1,368	$ 611	$ 337	$ 420

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

	Three Months Ended September 30, 2019						
Revenues from contracts with customers	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Rate-regulated electric revenues							
Residential	$ 865	$ 479	$ 352	$ 741	$ 311	$ 178	$ 252
Small commercial & industrial	393	109	64	147	41	48	58
Large commercial & industrial	141	63	116	297	222	26	49
Public authorities & electric railroads	12	9	7	17	11	3	3
Other[(a)]	222	63	82	164	58	50	56
Total rate-regulated electric revenues[(b)]	$ 1,633	$ 723	$ 621	$ 1,366	$ 643	$ 305	$ 418
Rate-regulated natural gas revenues							
Residential	$ —	$ 38	$ 49	$ 9	$ —	$ 9	$ —
Small commercial & industrial	—	17	9	4	—	4	—
Large commercial & industrial	—	—	20	1	—	1	—
Transportation	—	5	—	4	—	4	—
Other[(c)]	—	2	5	2	—	2	—
Total rate-regulated natural gas revenues[(d)]	$ —	$ 62	$ 83	$ 20	$ —	$ 20	$ —
Total rate-regulated revenues from contracts with customers	$ 1,633	$ 785	$ 704	$ 1,386	$ 643	$ 325	$ 418
Other revenues							
Revenues from alternative revenue programs	$ (56)	$ (11)	$ (5)	$ (9)	$ (3)	$ (6)	$ 1
Other rate-regulated electric revenues[(e)]	6	4	3	3	2	—	—
Other rate-regulated natural gas revenues[(e)]	—	—	1	—	—	—	—
Total other revenues	$ (50)	$ (7)	$ (1)	$ (6)	$ (1)	$ (6)	$ 1
Total rate-regulated revenues for reportable segments	$ 1,583	$ 778	$ 703	$ 1,380	$ 642	$ 319	$ 419

(a) Includes revenues from transmission revenue from PJM, wholesale electric revenue and mutual assistance revenue.
(b) Includes operating revenues from affiliates of $15 million, $3 million, $3 million, $6 million, $3 million, $3 million and $1 million at ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE, respectively, in 2020 and $4 million, $1 million, $2 million, $4 million, $2 million, $1 million and $1 million at ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE, respectively, in 2019.
(c) Includes revenues from off-system natural gas sales.
(d) Includes operating revenues from affiliates of less than $1 million and $3 million at PECO and BGE, respectively, in 2020 and less than $1 million and $4 million at PECO and BGE, respectively, in 2019.
(e) Includes late payment charge revenues.

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

Nine Months Ended September 30, 2020 and 2019

	Generation	ComEd	PECO	BGE	PHI	Other[a]	Intersegment Eliminations	Exelon
Operating revenues[b]:								
2020								
Competitive businesses electric revenues	$ 11,367	$ —	$ —	$ —	$ —	$ —	$ (920)	$ 10,447
Competitive businesses natural gas revenues	1,348	—	—	—	—	—	(3)	1,345
Competitive businesses other revenues	557	—	—	—	—	—	(5)	552
Rate-regulated electric revenues	—	4,499	1,948	1,763	3,425	—	(50)	11,585
Rate-regulated natural gas revenues	—	—	358	521	116	—	(5)	990
Shared service and other revenues	—	—	—	—	13	1,440	(1,447)	6
Total operating revenues	$ 13,272	$ 4,499	$ 2,306	$ 2,284	$ 3,554	$ 1,440	$ (2,430)	$ 24,925
2019								
Competitive businesses electric revenues	$ 12,365	$ —	$ —	$ —	$ —	$ —	$ (840)	$ 11,525
Competitive businesses natural gas revenues	1,479	—	—	—	—	—	—	1,479
Competitive businesses other revenues	436	—	—	—	—	—	(4)	432
Rate-regulated electric revenues	—	4,342	1,901	1,817	3,574	—	(25)	11,609
Rate-regulated natural gas revenues	—	—	432	510	116	—	(12)	1,046
Shared service and other revenues	—	—	—	—	10	1,410	(1,415)	5
Total operating revenues	$ 14,280	$ 4,342	$ 2,333	$ 2,327	$ 3,700	$ 1,410	$ (2,296)	$ 26,096
Intersegment revenues[c]:								
2020	$ 932	$ 31	$ 7	$ 16	$ 13	$ 1,435	$ (2,430)	$ 4
2019	844	13	4	18	11	1,410	(2,300)	—
Depreciation and amortization:								
2020	$ 1,161	$ 841	$ 259	$ 405	$ 585	$ 61	$ —	$ 3,312
2019	1,221	767	247	368	562	72	—	3,237
Operating expenses:								
2020	$ 12,674	$ 3,798	$ 1,900	$ 1,903	$ 3,057	$ 1,452	$ (2,397)	$ 22,387
2019	13,333	3,431	1,783	1,936	3,106	1,405	(2,291)	22,703
Interest expense, net:								
2020	$ 277	$ 287	$ 108	$ 99	$ 201	$ 269	$ —	$ 1,241
2019	336	268	100	89	197	231	—	1,221

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

	Generation	ComEd	PECO	BGE	PHI	Other[(a)]	Intersegment Eliminations	Exelon
Income (loss) before income taxes:								
2020	$ 532	$ 446	$ 310	$ 299	$ 340	$ (262)	$ —	$ 1,665
2019	1,355	674	461	320	436	(218)	—	3,028
Income Taxes:								
2020	$ 41	$ 142	$ (7)	$ 26	$ (77)	$ 16	$ —	$ 141
2019	388	130	51	59	25	(27)	—	626
Net income (loss):								
2020	$ 485	$ 304	$ 317	$ 273	$ 418	$ (278)	$ —	$ 1,519
2019	784	544	410	261	412	(191)	—	2,220
Capital Expenditures:								
2020	$ 1,212	$ 1,583	$ 824	$ 838	$ 1,072	$ 77	$ —	$ 5,606
2019	1,282	1,413	675	842	1,006	41	—	5,259
Total assets:								
September 30, 2020	$ 47,372	$ 34,243	$ 12,334	$ 11,370	$ 23,394	$ 9,070	$ (10,016)	$ 127,767
December 31, 2019	48,995	32,765	11,469	10,634	22,719	8,484	(10,089)	124,977

____
(a) Other primarily includes Exelon's corporate operations, shared service entities, and other financing and investment activities.
(b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 17 — Supplemental Financial Information for additional information on total utility taxes.
(c) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in Operating revenues in the Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Related Party Transactions for additional information on intersegment revenues.

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

PHI:

	Pepco	DPL	ACE	Other[(a)]	Intersegment Eliminations	PHI
Operating revenues[(b)]:						
2020						
Rate-regulated electric revenues	$ 1,650	$ 838	$ 952	$ —	$ (15)	$ 3,425
Rate-regulated natural gas revenues	—	116	—	—	—	116
Shared service and other revenues	—	—	—	279	(266)	13
Total operating revenues	$ 1,650	$ 954	$ 952	$ 279	$ (281)	$ 3,554
2019						
Rate-regulated electric revenues	$ 1,748	$ 871	$ 966	$ (1)	$ (10)	$ 3,574
Rate-regulated natural gas revenues	—	116	—	—	—	116
Shared service and other revenues	—	—	—	298	(288)	10
Total operating revenues	$ 1,748	$ 987	$ 966	$ 297	$ (298)	$ 3,700
Intersegment revenues[(c)]:						
2020	$ 6	$ 7	$ 3	$ 278	$ (281)	$ 13
2019	5	5	2	297	(298)	11
Depreciation and amortization:						
2020	$ 282	$ 143	$ 134	$ 26	$ —	$ 585
2019	281	138	114	29	—	562
Operating expenses:						
2020	$ 1,364	$ 843	$ 847	$ 284	$ (281)	$ 3,057
2019	1,444	820	838	302	(298)	3,106
Interest expense, net:						
2020	$ 103	$ 47	$ 45	$ 6	$ —	$ 201
2019	100	45	44	8	—	197
Income (loss) before income taxes:						
2020	$ 211	$ 71	$ 67	$ (9)	$ —	$ 340
2019[(d)]	226	132	89	(11)	—	436
Income Taxes:						
2020	$ (16)	$ (20)	$ (39)	$ (2)	$ —	$ (77)
2019	9	16	2	(2)	—	25
Net income (loss):						
2020	$ 227	$ 91	$ 106	$ (6)	$ —	$ 418
2019	217	116	87	(8)	—	412
Capital Expenditures:						
2020	$ 512	$ 278	$ 281	$ 1	$ —	$ 1,072
2019	455	245	300	6	—	1,006
Total assets:						
September 30, 2020	$ 9,227	$ 4,992	$ 4,201	$ 5,239	$ (265)	$ 23,394
December 31, 2019[(d)]	8,661	4,830	3,933	5,335	(40)	22,719

(a) Other primarily includes PHI's corporate operations, shared service entities, and other financing and investment activities.
(b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 17 — Supplemental Financial Information for additional information on total utility taxes.
(c) Includes intersegment revenues with ComEd, BGE, and PECO, which are eliminated at Exelon.
(d) The Income (loss) before income taxes and Total assets amounts in Other and Intersegment Eliminations have been adjusted by an offsetting $422 million and $5.7 billion, respectively, for consistency with the Exelon consolidating disclosure above.

The following tables disaggregate the Registrants' revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. For Generation, the disaggregation of revenues reflects Generation's two primary products of power sales and natural gas sales, with further disaggregation of power sales provided by geographic region. For the Utility Registrants, the disaggregation of revenues reflects the two primary utility services of rate-regulated electric sales and rate-regulated natural gas sales (where applicable), with further disaggregation of these tariff sales provided by major customer groups. Exelon's disaggregated revenues are consistent with Generation and the Utility Registrants, but exclude any intercompany revenues.

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

Competitive Business Revenues (Generation):

	Nine Months Ended September 30, 2020				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 3,692	$ (152)	$ 3,540	$ 21	$ 3,561
Midwest	2,773	240	3,013	(6)	3,007
New York	1,074	(12)	1,062	(1)	1,061
ERCOT	579	155	734	20	754
Other Power Regions	2,718	300	3,018	(34)	2,984
Total Competitive Businesses Electric Revenues	10,836	531	11,367	—	11,367
Competitive Businesses Natural Gas Revenues	881	467	1,348	—	1,348
Competitive Businesses Other Revenues[c]	268	289	557	—	557
Total Generation Consolidated Operating Revenues	$ 11,985	$ 1,287	$ 13,272	$ —	$ 13,272

	Nine Months Ended September 30, 2019				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 3,798	$ 9	$ 3,807	$ 2	$ 3,809
Midwest	3,083	172	3,255	(31)	3,224
New York	1,195	16	1,211	—	1,211
ERCOT	594	198	792	13	805
Other Power Regions	2,849	451	3,300	(46)	3,254
Total Competitive Businesses Electric Revenues	11,519	846	12,365	(62)	12,303
Competitive Businesses Natural Gas Revenues	1,041	438	1,479	62	1,541
Competitive Businesses Other Revenues[c]	343	93	436	—	436
Total Generation Consolidated Operating Revenues	$ 12,903	$ 1,377	$ 14,280	$ —	$ 14,280

(a) Includes all wholesale and retail electric sales to third parties and affiliated sales to the Utility Registrants.
(b) Includes revenues from derivatives and leases.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Includes unrealized mark-to-market gains of $238 million and $64 million in 2020 and 2019, respectively, and elimination of intersegment revenues.

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

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

	Nine Months Ended September 30, 2020			Nine Months Ended September 30, 2019		
	RNF from external customers[a]	Intersegment RNF	Total RNF	RNF from external customers[a]	Intersegment RNF	Total RNF
Mid-Atlantic	$ 1,660	$ 23	$ 1,683	$ 2,007	$ 16	$ 2,023
Midwest	2,180	(2)	2,178	2,269	(22)	2,247
New York	714	11	725	800	10	810
ERCOT	311	14	325	252	(27)	225
Other Power Regions	608	(70)	538	542	(64)	478
Total Revenues net of purchased power and fuel expense for Reportable Segments	5,473	(24)	5,449	5,870	(87)	5,783
Other[b]	838	24	862	262	87	349
Total Generation Revenues net of purchased power and fuel expense	$ 6,311	$ —	$ 6,311	$ 6,132	$ —	$ 6,132

(a) Includes purchases and sales from/to third parties and affiliated sales to the Utility Registrants.
(b) Other represents activities not allocated to a region. See text above for a description of included activities. Includes unrealized mark-to-market gains of $472 million and losses of $84 million in 2020 and 2019, respectively, accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 6 - Early Plant Retirements of $24 million, which includes an impairment charge of $10 million, and $13 million decrease to revenue net of purchased power and fuel expense in 2020 and 2019, respectively, and the elimination of intersegment RNF.

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

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

	Nine Months Ended September 30, 2020						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$ 2,389	$ 1,277	$ 1,034	$ 1,825	$ 779	$ 501	$ 545
Small commercial & industrial	1,067	291	183	355	101	127	127
Large commercial & industrial	388	174	311	755	558	66	131
Public authorities & electric railroads	33	21	20	45	25	10	10
Other[a]	663	171	233	471	166	148	159
Total rate-regulated electric revenues[b]	$ 4,540	$ 1,934	$ 1,781	$ 3,451	$ 1,629	$ 852	$ 972
Rate-regulated natural gas revenues							
Residential	$ —	$ 252	$ 342	$ 68	$ —	$ 68	$ —
Small commercial & industrial	—	86	55	30	—	30	—
Large commercial & industrial	—	—	96	3	—	3	—
Transportation	—	18	—	10	—	10	—
Other[c]	—	3	16	5	—	5	—
Total rate-regulated natural gas revenues[d]	$ —	$ 359	$ 509	$ 116	$ —	$ 116	$ —
Total rate-regulated revenues from contracts with customers	$ 4,540	$ 2,293	$ 2,290	$ 3,567	$ 1,629	$ 968	$ 972
Other revenues							
Revenues from alternative revenue programs	$ (51)	$ 10	$ (10)	$ (15)	$ 20	$ (15)	$ (20)
Other rate-regulated electric revenues[e]	10	3	3	2	1	1	—
Other rate-regulated natural gas revenues[e]	—	—	1	—	—	—	—
Total other revenues	$ (41)	$ 13	$ (6)	$ (13)	$ 21	$ (14)	$ (20)
Total rate-regulated revenues for reportable segments	$ 4,499	$ 2,306	$ 2,284	$ 3,554	$ 1,650	$ 954	$ 952

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

Note 4 — Segment Information

Revenues from contracts with customers	Nine Months Ended September 30, 2019 ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$ 2,221	$ 1,231	$ 1,019	$ 1,816	$ 792	$ 499	$ 525
Small commercial & industrial	1,103	304	193	387	114	141	132
Large commercial & industrial	399	163	335	843	633	75	135
Public authorities & electric railroads	35	23	20	47	27	10	10
Other[(a)]	660	186	242	481	166	151	164
Total rate-regulated electric revenues[(b)]	$ 4,418	$ 1,907	$ 1,809	$ 3,574	$ 1,732	$ 876	$ 966
Rate-regulated natural gas revenues							
Residential	$ —	$ 285	$ 327	$ 64	$ —	$ 64	$ —
Small commercial & industrial	—	122	55	30	—	30	—
Large commercial & industrial	—	1	93	4	—	4	—
Transportation	—	18	—	11	—	11	—
Other[(c)]	—	5	19	6	—	6	—
Total rate-regulated natural gas revenues[(d)]	$ —	$ 431	$ 494	$ 115	$ —	$ 115	$ —
Total rate-regulated revenues from contracts with customers	$ 4,418	$ 2,338	$ 2,303	$ 3,689	$ 1,732	$ 991	$ 966
Other revenues							
Revenues from alternative revenue programs	$ (98)	$ (16)	$ 11	$ 4	$ 10	$ (6)	$ —
Other rate-regulated electric revenues[(e)]	22	10	10	7	6	1	—
Other rate-regulated natural gas revenues[(e)]	—	1	3	—	—	1	—
Total other revenues	$ (76)	$ (5)	$ 24	$ 11	$ 16	$ (4)	$ —
Total rate-regulated revenues for reportable segments	$ 4,342	$ 2,333	$ 2,327	$ 3,700	$ 1,748	$ 987	$ 966

(a) Includes revenues from transmission revenue from PJM, wholesale electric revenue and mutual assistance revenue.
(b) Includes operating revenues from affiliates of $31 million, $6 million, $9 million, $13 million, $6 million, $7 million and $3 million at ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE, respectively, in 2020 and $13 million, $4 million, $5 million, $11 million, $5 million, $5 million and $2 million at ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE, respectively, in 2019.
(c) Includes revenues from off-system natural gas sales.
(d) Includes operating revenues from affiliates of $1 million and $7 million at PECO and BGE, respectively, in 2020 and less than $1 million and $13 million at PECO and BGE, respectively, in 2019.
(e) Includes late payment charge revenues.

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

5. Accounts Receivable (All Registrants)

Allowance for Credit Losses on Accounts Receivable (All Registrants)

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

	Three Months Ended September 30, 2020								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of June 30, 2020	$ 261	$ 33	$ 72	$ 71	$ 23	$ 62	$ 24	$ 18	$ 20
Plus: Current Period Provision for Expected Credit Losses[a]	114	1	37	27	14	35	11	7	17
Less: Write-offs, net of recoveries[b]	17	1	4	2	2	8	—	3	5
Balance as of September 30, 2020	$ 358	$ 33	$ 105	$ 96	$ 35	$ 89	$ 35	$ 22	$ 32

	Nine Months Ended September 30, 2020								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of December 31, 2019	$ 243	$ 80	$ 59	$ 55	$ 12	$ 37	$ 13	$ 11	$ 13
Plus: Current Period Provision for Expected Credit Losses[a]	222	13	62	56	28	63	24	14	25
Less: Write-offs, net of recoveries[b]	51	4	16	15	5	11	2	3	6
Less: Sale of customer accounts receivable[c]	56	56	—	—	—	—	—	—	—
Balance as of September 30, 2020	$ 358	$ 33	$ 105	$ 96	$ 35	$ 89	$ 35	$ 22	$ 32

____
(a) For the Utility Registrants, the increase is primarily as a result of increased aging of receivables, the temporary suspension of customer disconnections for non-payment, temporary cessation of new late payment fees, and reconnection of service to customers previously disconnected due to COVID-19.
(b) Recoveries were not material to the Registrants.
(c) See below for additional information on the sale of customer accounts receivable at Generation in the second quarter of 2020.

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

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

	Three Months Ended September 30, 2020								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of June 30, 2020	$ 61	$ —	$ 22	$ 7	$ 6	$ 26	$ 11	$ 7	$ 8
Plus: Current Period Provision for Expected Credit Losses	15	—	5	1	3	6	2	1	3
Less: Write-offs, net of recoveries[(a)]	1	—	—	1	—	—	—	—	—
Balance as of September 30, 2020	$ 75	$ —	$ 27	$ 7	$ 9	$ 32	$ 13	$ 8	$ 11

	Nine Months Ended September 30, 2020								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of December 31, 2019	$ 48	$ —	$ 20	$ 7	$ 5	$ 16	$ 7	$ 4	$ 5
Plus: Current Period Provision for Expected Credit Losses	36	—	9	3	7	17	6	4	7
Less: Write-offs, net of recoveries[(a)]	9	—	2	3	3	1	—	—	1
Balance as of September 30, 2020	$ 75	$ —	$ 27	$ 7	$ 9	$ 32	$ 13	$ 8	$ 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.

	Unbilled customer revenues[(a)]								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
September 30, 2020	$ 672	$ 139	$ 193	$ 98	$ 115	$ 127	$ 72	$ 37	$ 18
December 31, 2019	1,535	807	218	146	170	194	100	61	33

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

Sales of Customer Accounts Receivable (Exelon and Generation)

On April 8, 2020, NER, a bankruptcy remote, special purpose entity, which is wholly-owned by Generation, entered into a revolving accounts receivable financing arrangement with a number of financial institutions and a commercial paper conduit (the Purchasers) to sell certain customer accounts receivable (the Facility). The Facility, whose maximum capacity is $750 million, is scheduled to expire on April 7, 2021, unless renewed by the mutual consent of the parties in accordance with its terms. Under the Facility, NER may sell eligible short-term customer accounts receivable to the Purchasers in exchange for cash and subordinated interest. The transfers are reported as sales of receivables in Exelon's and Generation's consolidated financial statements. The subordinated interest in collections upon the receivables sold to the Purchasers is referred to as the DPP, which is reflected in Other current assets on Exelon's and Generation's Consolidated Balance Sheet.

On April 8, 2020, Generation derecognized and transferred approximately $1.2 billion of receivables at fair value to the Purchasers in exchange for approximately $500 million in cash purchase price and $650 million of DPP.

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

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

	As of September 30, 2020
Derecognized receivables transferred at fair value[(a)]	$ 1,232
Cash proceeds received	500
DPP	732

(a) Includes additional customer accounts receivable sold into the Facility of $4,515 million since the start of the financing agreement.

	Three months ended September 30, 2020	Nine months ended September 30, 2020
Loss on sale of receivables[(a)]	$ 8	$ 23

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

	Nine months ended September 30, 2020
Proceeds from new transfers	$ 1,889
Cash collections received on DPP	2,518
Cash collections reinvested in the Facility	4,407

Generation’s risk of loss following the transfer of accounts receivable is limited to the DPP outstanding. Payment of DPP is not subject to significant risks other than delinquencies and credit losses on accounts receivable transferred, which have historically been and are expected to be immaterial. Generation continues to service the receivables sold in exchange for a servicing fee. Generation did not record a servicing asset or liability as the servicing fees were immaterial.

Generation reflected 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 of the Consolidated Statements of Cash Flows.

See Note 13 — Fair Value of Financial Assets and Liabilities and Note 16 — Variable Interest Entities for additional information.

Other Purchases and Sales of Customer and Other Accounts Receivables (All Registrants)

Generation is required, under supplier tariffs in ISO-NE, MISO, NYISO, and PJM, to sell customer and other receivables to utility companies, which include the Utility Registrants. The Utility Registrants are required, under separate legislation and regulations in Illinois, Pennsylvania, Maryland, District of Columbia, and New Jersey, to purchase certain receivables from alternative retail electric and, as applicable, natural gas suppliers that participate in the utilities' consolidated billing. The following tables present the total receivables purchased and sold.

	Nine Months Ended September 30, 2020								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Total Receivables Purchased	$ 2,698	$ —	$ 865	$ 786	$ 508	$ 787	$ 484	$ 160	$ 143
Total Receivables Sold	542	790	—	—	—	—	—	—	—
Related Party Transactions:									
Receivables purchased from Generation	—	—	34	67	75	72	51	13	8
Receivables sold to the Utility Registrants	—	248	—	—	—	—	—	—	—

6. Early Plant Retirements (Exelon and Generation)

Exelon and Generation continuously evaluate factors that affect the current and expected economic value of Generation's plants, including, but not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions to ensure plants are fairly compensated for benefits they provide through their carbon-free emissions, reliability, or fuel security, and the impact of potential rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules. The precise timing of an early retirement date for any plant, and the resulting financial statement impacts, may be affected by many factors, including the status of potential regulatory or legislative solutions, results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and NDT fund requirements for nuclear plants, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity or other obligations, and where applicable, just prior to its next scheduled nuclear refueling outage.

Nuclear Generation

In 2015 and 2016, Generation identified the Clinton and Quad Cities nuclear plants in Illinois, Ginna and Nine Mile Point nuclear plants in New York, and TMI nuclear plant in Pennsylvania as having the greatest risk of early retirement based on economic valuation and other factors. In 2017, PSEG made public similar financial challenges facing its New Jersey nuclear plants, including Salem, of which Generation owns a 42.59% ownership interest. PSEG is the operator of Salem and also has the decision-making authority to retire Salem.

Assuming the continued effectiveness of the Illinois ZES, New Jersey ZEC program, and the New York CES, Generation and CENG, through its ownership of Ginna and Nine Mile Point, no longer consider Clinton, Quad Cities, Salem, Ginna, or Nine Mile Point to be at heightened risk for early retirement. However, to the extent the Illinois ZES, New Jersey ZEC program, or the New York CES do not operate as expected over their full terms, each of these plants could again be at heightened risk for early retirement, which could have a material impact on Exelon's and Generation's future financial statements. In addition, FERC's December 19, 2019 order on the MOPR in PJM may undermine the continued effectiveness of the Illinois ZES and the New Jersey ZEC program unless Illinois and New Jersey implement an FRR mechanism under which the Generation plants in these states would be removed from PJM's capacity auction. See Note 2 — Regulatory Matters for additional information on the New Jersey ZEC program, New York CES, and FERC's December 19, 2019 order and Note 3 — Regulatory Matters of the 2019 Form 10-K for additional information on the Illinois ZES.

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

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

Generation's Dresden, Byron, and Braidwood nuclear plants in Illinois are also showing increased signs of economic distress, in a market that does not currently compensate them for their unique contribution to grid resiliency and their ability to produce large amounts of energy without carbon and air pollution. The May 2018 PJM capacity auction for the 2021-2022 planning year resulted in the largest volume of nuclear capacity ever not selected in the auction, including all of Dresden, and portions of Byron and Braidwood. While all of LaSalle's capacity did clear in the 2021-2022 planning year auction, Generation has become increasingly concerned about the economic viability of this plant as well in a landscape where energy market prices remain depressed and energy market rules remain fatally flawed.

On August 27, 2020, Generation announced that it intends to permanently cease generation operations at Byron in September 2021 and at Dresden in November 2021. The current NRC licenses for Byron Units 1 and 2 expire in 2044 and 2046, respectively, and the licenses for Dresden Units 2 and 3 expire in 2029 and 2031, respectively.

As a result of the decision to early retire Byron and Dresden, Exelon and Generation recognized certain one-time charges in the third quarter of 2020 related to materials and supplies inventory reserve adjustments, employee-related costs including severance benefit costs further discussed below, and construction work-in-progress impairments, among other items. In addition, as a result of the decisions to early retire Byron and Dresden, there are ongoing annual financial impacts stemming from shortening the expected economic useful lives of these nuclear plants primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and changes in ARO accretion expense associated with the changes in decommissioning timing and cost assumptions to reflect an earlier retirement date. See Note 7 - Nuclear Decommissioning for additional information on changes to the nuclear decommissioning ARO balance and Note 8 — Asset Impairments for impairment assessment considerations given to the Midwest asset group as a result of the early retirement decision. The total impact on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income is summarized in the table below.

Income statement expense (pre-tax)	Three and Nine Months Ended September 30, 2020[(a)]	Three Months Ended September 30, 2019[(b)]	Nine Months Ended September 30, 2019[(b)]
Depreciation and amortization			
Accelerated depreciation[(c)]	$ 254	$ 71	$ 216
Accelerated nuclear fuel amortization	14	3	13
Operating and maintenance			
One-time charges	220	—	—
Other charges[(d)]	34	39	(44)
Contractual offset[(e)]	(129)	—	—
Total	$ 393	$ 113	$ 185

(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 Dresden, reflects the net impacts associated with the remeasurement of the ARO. See Note 7 - Nuclear Decommissioning for additional information. For TMI, primarily reflects the net impacts associated with the remeasurement of the ARO. See Note 9 - Asset Retirement Obligations of the 2019 Form 10-K for additional information.
(e) Reflects contractual offset for ARO accretion, ARC depreciation, and net impacts associated with the remeasurement of the ARO. For Byron and Dresden, based on the regulatory agreement with the ICC, decommissioning-related activities are offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset results in an equal adjustment to the noncurrent payables to ComEd at Generation and an adjustment to the regulatory liabilities at ComEd. See Note 9 - Asset Retirement Obligations of the Exelon 2019 Form 10-K for additional information.

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

Severance benefit costs will be provided to employees impacted by the early retirements of Byron and Dresden, to the extent they are not redeployed to other nuclear plants. In the third quarter of 2020, Exelon and Generation recorded estimated severance expense of $81 million within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income. The final amount of severance benefit costs will depend on the specific employees severed.

The following table provides the balance sheet amounts as of September 30, 2020 for Exelon's and Generation's significant assets and liabilities associated with the Braidwood and LaSalle nuclear plants. Current depreciation provisions are based on the estimated useful lives of these nuclear generating stations, which reflect the first renewal of the operating licenses.

	Braidwood	LaSalle	Total
Asset Balances			
Materials and supplies inventory, net	$ 82	$ 107	$ 189
Nuclear fuel inventory, net	147	218	365
Completed plant, net	1,403	1,571	2,974
Construction work in progress	18	23	41
Liability Balances			
Asset retirement obligation	(570)	(926)	(1,496)
NRC License First Renewal Term	2046 (Unit 1) 2047 (Unit 2)	2042 (Unit 1) 2043 (Unit 2)	

Exelon continues to work with stakeholders on state policy solutions, while also advocating for broader market reforms at the regional and federal level. The absence of such solutions or reforms could result in future impairments of the Midwest asset group, or accelerated depreciation for specific plants over their shortened estimated useful lives, both of which could have a material unfavorable impact on Exelon's and Generation's future results of operations.

Other Generation

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

On June 10, 2020, Generation filed a complaint with FERC against ISO-NE stating that ISO-NE failed to follow its tariff with respect to its evaluation of Mystic 8 and 9 for transmission security for the 2024 to 2025 Capacity Commitment Period (FCA 15) and that the modifications that ISO-NE made to its unfiled planning procedures to avoid retaining Mystic 8 and 9 should have been filed with FERC for approval. On August 17, 2020, FERC issued an order denying the complaint. As a result, on August 20, 2020, Exelon determined that Generation will permanently cease generation operations at Mystic 8 and 9 at the expiration of the cost of service commitment in May 2024. See Note 2 — Regulatory Matters for additional discussion of Mystic's cost of service agreement.

As a result of the decision to early retire Mystic 8 and 9, Exelon and Generation recognized $43 million of one-time charges related to an expected long-term maintenance contract termination and materials and supplies inventory reserve adjustments, among other items. In addition, there are annual financial impacts stemming from shortening the expected economic useful life of Mystic 8 and 9 primarily related to accelerated depreciation of plant assets. Exelon and Generation recorded incremental Depreciation and amortization expense of $6 million in the third quarter of 2020. See Note 8 — Asset Impairments for impairment assessment considerations of the New England Asset Group.

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

7. Nuclear Decommissioning (Exelon and Generation)

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations for financial accounting and reporting purposes, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models, and discount rates. Generation updates its ARO annually, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

The financial statement impact for changes in the ARO, on an individual unit basis, due to the changes in and timing of estimated cash flows generally result in a corresponding change in the unit's ARC within Property, plant, and equipment on Exelon's and Generation's Consolidated Balance Sheets. If the ARO decreases for a Non-Regulatory Agreement Unit without any remaining ARC, the corresponding change is recorded as decrease in Operating and maintenance expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

The following table provides a rollforward of the nuclear decommissioning ARO reflected in Exelon's and Generation's Consolidated Balance Sheets from December 31, 2019 to September 30, 2020:

Nuclear decommissioning ARO at December 31, 2019 [(a)]	$	10,504
Accretion expense		367
Net increase due to changes in, and timing of, estimated future cash flows		806
Costs incurred related to decommissioning plants		(59)
Nuclear decommissioning ARO at September 30, 2020 [(a)]	$	11,618

____
(a) Includes $93 million and $112 million as the current portion of the ARO at September 30, 2020 and December 31, 2019, respectively, which is included in Other current liabilities in Exelon's and Generation's Consolidated Balance Sheets.

During the nine months ended September 30, 2020, the net $806 million increase in the ARO for the changes in the amounts and timing of estimated decommissioning cash flows 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 6 — Early Plant Retirements for additional information.

NDT Funds

Exelon and Generation had NDT funds totaling $13,547 million and $13,353 million at September 30, 2020 and December 31, 2019, respectively. The NDT funds also include $115 million and $163 million for the current portion of the NDT funds at September 30, 2020 and December 31, 2019, respectively, which are included in Other current assets in Exelon's and Generation's Consolidated Balance Sheets. See Note 17 — Supplemental Financial Information for additional information on activities of the NDT funds.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life.

Generation filed its biennial decommissioning funding status report with the NRC on April 1, 2019 for all units, including its shutdown units, except for Zion Station which is included in a separate report to the NRC submitted by ZionSolutions, LLC. The status report demonstrated adequate decommissioning funding assurance as of December 31, 2018 for all units except for Clinton and Peach Bottom Unit 1. As of February 28, 2019, Clinton demonstrated adequate minimum funding assurance due to market recovery and no further action is required. This demonstration was also included in the April 1, 2019 submittal. On March 31, 2020, Generation filed its annual decommissioning funding status report with the NRC for Generation's shutdown units (excluding Zion

Station for the reason noted above). The annual status report demonstrated adequate decommissioning funding assurance as of December 31, 2019, for all of its shutdown reactors except for Peach Bottom Unit 1. As a former PECO plant, financial assurance for decommissioning Peach Bottom Unit 1 is provided by the NDT fund, collections from PECO ratepayers, and the ability to adjust those collections in accordance with the approved PAPUC tariff. No additional actions are required aside from the PAPUC filing in accordance with the tariff. See Note 9 — Asset Retirement Obligations of the Exelon 2019 Form 10-K for information regarding the amount collected from PECO ratepayers for decommissioning cost.

Generation will file its next decommissioning funding status report with the NRC by March 31, 2021. This report will reflect the status of decommissioning funding assurance as of December 31, 2020 and will include the impact of the announced early retirement of Byron and Dresden. A shortfall could require Exelon to post parental guarantee for Generation's share of the funding assurance. However, the amount of any required guarantee will ultimately depend on the decommissioning approach adopted at Byron and Dresden, the associated level of costs, and the decommissioning trust fund investment performance going forward.

8. Asset Impairments (Exelon and Generation)

The Registrants evaluate the carrying value of long-lived assets or asset groups for recoverability whenever events or changes in circumstances indicate that the carrying value of those assets may not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life. The Registrants determine if long-lived assets or asset groups are impaired by comparing the undiscounted expected future cash flows to the carrying value. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. The fair value analysis is primarily based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures, and discount rates. A variation in the assumptions used could lead to a different conclusion regarding the recoverability of an asset or asset group and, thus, could potentially result in material future impairments of the Registrant's long-lived assets.

Antelope Valley Solar Facility

Generation's Antelope Valley, a 242 MW solar facility in Lancaster, CA, sells all of its output to PG&E through a PPA. As a result of the PG&E bankruptcy filing in the first quarter of 2019, Generation completed a comprehensive review of Antelope Valley's estimated undiscounted future cash flows and no impairment charge was recorded.

The United States Bankruptcy Court entered an order on June 20, 2020 confirming PG&E's plan of reorganization. On July 1, 2020 the plan became effective, and PG&E emerged from bankruptcy. Under the confirmed plan, PG&E will continue to honor the existing PPA agreement with Antelope Valley.

See Note 12 - Debt and Credit Agreements for additional information.

New England Asset Group

During the first quarter of 2018, Mystic Unit 9 did not clear in the ISO-NE capacity auction for the 2021 - 2022 planning year. On March 29, 2018, Generation notified grid operator ISO-NE of its plans to early retire its Mystic Units 8 and 9 absent regulatory reforms on June 1, 2022. These events suggested that the carrying value of the New England asset group may be impaired. In the second quarter of 2018, Generation completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group and no impairment charge was required.

In the third quarter of 2020, in conjunction with the retirement announcement of Mystic Units 8 and 9, Generation completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group and concluded that the estimated undiscounted future cash flows and fair value of the New England asset group were less than their carrying values. As a result, a pre-tax impairment charge of $500 million was recorded in the third quarter of 2020 within Operating and maintenance expense in Exelon's and Generation's

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

Consolidated Statements of Operations and Comprehensive Income. See Note 6 - Early Plant Retirements for additional information.

Midwest Asset Group

In the third quarter of 2020, in conjunction with the retirement announcements of the Byron and Dresden nuclear plants, Generation completed a comprehensive review of the estimated undiscounted future cash flows of the Midwest asset group and no impairment charge was required.

We will continue to monitor the recoverability of the carrying value of the Midwest asset group as certain other nuclear plants in Illinois are also showing increased signs of economic distress, which could lead to an early retirement. See Note 6 - Early Plant Retirements for additional information.

Equity Method Investments in Certain Distributed Energy Companies

In the third quarter of 2019, Generation's equity method investments in certain distributed energy companies were fully impaired due to an other-than-temporary decline in market conditions and underperforming projects. Exelon and Generation recorded a pre-tax impairment charge of $164 million in Equity in losses of unconsolidated affiliates and an offsetting pre-tax $96 million in Net income attributable to noncontrolling interests in their Consolidated Statements of Operations and Comprehensive Income. As a result, Generation accelerated the amortization of investment tax credits associated with these companies and Exelon and Generation recorded a benefit of $46 million in Income taxes. The impairment charge and the accelerated amortization of investment tax credits resulted in a net $15 million decrease to Exelon's and Generation's earnings. See Note 16 — Variable Interest Entities for additional information.

9. Income Taxes (All Registrants)

Rate Reconciliation

The effective income tax rate from continuing operations varies from the U.S. federal statutory rate principally due to the following:

	Three Months Ended September 30, 2020[a]								
	Exelon	Generation	ComEd	PECO[b]	BGE	PHI[c]	Pepco	DPL	ACE[c]
U.S. Federal statutory rate	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	12.3	(10.3)	8.1	(6.2)	5.1	5.5	4.6	6.6	6.9
Qualified NDT fund income	13.2	47.4	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.4)	(4.5)	(0.2)	—	(0.1)	(0.2)	(0.1)	(0.2)	(0.3)
Plant basis differences	(4.3)	—	(0.6)	(23.3)	(1.2)	(1.5)	(2.1)	(0.4)	(1.3)
Production tax credits and other credits	(3.0)	(9.2)	(0.4)	—	(0.8)	(0.5)	(0.5)	(0.5)	(0.4)
Noncontrolling interests	0.8	2.9	—	—	—	—	—	—	—
Excess deferred tax amortization	(10.1)	—	(5.6)	(3.8)	(10.6)	(24.9)	(20.0)	(23.6)	(36.8)
Tax settlements	(0.2)	(0.7)	—	—	—	—	—	—	—
Other	(0.8)	(0.9)	1.1	(0.8)	(0.3)	0.1	(0.4)	0.7	0.6
Effective income tax rate	27.5%	45.7%	23.4%	(13.1)%	13.1%	(0.5)%	2.5%	3.6%	(10.3)%

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

	Three Months Ended September 30, 2019[a]								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	6.4	5.2	8.1	(0.3)	6.3	4.8	1.9	6.6	6.9
Qualified NDT fund income	3.2	7.1	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(4.1)	(8.9)	(0.2)	—	(0.1)	(0.2)	(0.1)	(0.2)	(0.3)
Plant basis differences	(1.7)	—	(1.0)	(7.5)	(1.1)	(1.8)	(2.6)	(0.6)	(1.9)
Production tax credits and other credits	(1.2)	(2.7)	—	—	—	—	—	—	—
Noncontrolling interests	(2.2)	(4.8)	—	—	—	—	—	—	—
Excess deferred tax amortization	(6.5)	—	(9.9)	(3.6)	(8.0)	(17.7)	(16.3)	(13.5)	(23.3)
Other	0.7	0.5	0.4	(0.5)	(0.2)	0.8	1.0	(0.1)	0.7
Effective income tax rate	15.6%	17.4%	18.4%	9.1%	17.9%	6.9%	4.9%	13.2%	3.1%

	Nine Months Ended September 30, 2020[a]								
	Exelon	Generation[d]	ComEd[e]	PECO[b]	BGE[c]	PHI[c]	Pepco[c]	DPL[c]	ACE[c]
U.S. Federal statutory rate	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	9.3	—	12.7	(3.4)	5.5	5.0	4.2	6.5	6.8
Qualified NDT fund income	3.2	10.0	—	—	—	—	—	—	—
Deferred Prosecution Agreement payments	2.5	—	9.4	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.2)	(3.2)	(0.3)	—	(0.1)	(0.2)	(0.1)	(0.3)	(0.5)
Plant basis differences	(4.0)	—	(0.9)	(15.9)	(1.8)	(2.2)	(2.4)	(0.5)	(3.7)
Production tax credits and other credits	(2.6)	(7.0)	(0.4)	—	(0.4)	(0.3)	(0.3)	(0.2)	(0.4)
Noncontrolling interests	1.0	3.1	—	—	—	—	—	—	—
Excess deferred tax amortization	(15.8)	—	(11.8)	(3.5)	(15.0)	(45.3)	(29.2)	(53.6)	(81.4)
Tax settlements	(5.0)	(15.7)	—	—	—	—	—	—	—
Other	0.1	(0.5)	2.1	(0.5)	(0.5)	(0.6)	(0.8)	(1.1)	—
Effective income tax rate	8.5%	7.7%	31.8%	(2.3)%	8.7%	(22.6)%	(7.6)%	(28.2)%	(58.2)%

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

	Nine Months Ended September 30, 2019[(a)]								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	5.1	4.2	8.2	—	6.4	4.8	2.0	6.7	6.9
Qualified NDT fund income	5.3	11.9	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.9)	(4.0)	(0.2)	—	(0.1)	(0.2)	(0.1)	(0.2)	(0.3)
Plant basis differences	(1.6)	—	(0.7)	(6.8)	(1.1)	(1.8)	(2.3)	(0.6)	(2.0)
Production tax credits and other credits	(1.0)	(2.1)	—	—	—	—	—	—	—
Noncontrolling interests	(1.0)	(2.3)	—	—	—	—	—	—	—
Excess deferred tax amortization	(6.0)	—	(9.2)	(2.9)	(7.9)	(18.6)	(17.3)	(15.0)	(23.4)
Other	0.8	(0.1)	0.2	(0.2)	0.1	0.5	0.7	0.2	—
Effective income tax rate	20.7%	28.6%	19.3%	11.1%	18.4%	5.7%	4.0%	12.1%	2.2%

(a) Positive percentages represent income tax expense. Negative percentages represent income tax benefit.
(b) At PECO, the lower effective tax rate is primarily related to an increase in plant basis differences attributable to storm repairs.
(c) At BGE, PHI, Pepco, DPL, and ACE, the lower effective tax rate is primarily attributable to accelerated amortization of transmission related deferred income tax regulatory liabilities as a result of regulatory settlements. See Note 2 — Regulatory Matters for additional information.
(d) At Generation, the lower effective tax rate is primarily attributable to tax settlements.
(e) At ComEd, the higher effective tax rate is primarily related to the nondeductible Deferred Prosecution Agreement payments. See Note 14 — Commitments and Contingencies for additional information.

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

Accounting for Uncertainty in Income Taxes

Exelon, Generation, PHI, and ACE have the following unrecognized tax benefits as of September 30, 2020 and December 31, 2019. ComEd, PECO, BGE, Pepco, and DPL's amounts are not material.

	Exelon	Generation	PHI	ACE
September 30, 2020	$ 125	$ 49	$ 53	$ 16
December 31, 2019	507	441	48	14

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

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

The following table represents Exelon's, PHI's, and ACE's unrecognized federal and state tax benefits that could significantly decrease within the 12 months after the reporting date as a result of completing audits, potential settlements, refund claims, and the outcomes of pending court cases as of September 30, 2020. Generation's, ComEd's, PECO's, BGE's, Pepco's, and DPL's amounts are not material.

Exelon	PHI	ACE(a)
$ 14	$ 14	$ 14

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

Other Income Tax Matters

State Income Tax Law Changes

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

Long-Term Marginal State Income Tax Rate (All Registrants)

In the third quarter of 2020 and 2019, Exelon updated its marginal state income tax rates for changes in state apportionment. The changes in marginal rates in the third quarter of 2020 resulted in an increase of $66 million and a decrease of $26 million to the deferred income tax liability at Exelon and Generation, respectively, as of September 30, 2020. The changes in marginal rates in the third quarter of 2019 resulted in an increase of $23 million and $9 million to the deferred income tax liability at Exelon and Generation, respectively, as of September 30, 2019. Exelon and Generation recorded a corresponding adjustment to income tax expense, net of federal taxes, in each of those respective periods.

Allocation of Tax Benefits (All Registrants)

Generation and the Utility Registrants are all party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit.

The following table presents the allocation of federal tax benefits from Exelon under the Tax Sharing Agreement.

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

	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
September 30, 2020	$ 64	$ 14	$ 17	$ —	$ 17	$ 8	$ 6	$ 1
December 31, 2019	41	—	14	3	7	6	1	—

10. Retirement Benefits (All Registrants)

Defined Benefit Pension and OPEB

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

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

A portion of the net periodic benefit cost for all plans is capitalized within the Consolidated Balance Sheets. The following table presents the components of Exelon's net periodic benefit costs, prior to capitalization, for the three and nine months ended September 30, 2020 and 2019.

	Pension Benefits Three Months Ended September 30,		OPEB Three Months Ended September 30,	
	2020	2019	2020	2019
Components of net periodic benefit cost:				
Service cost	$ 97	$ 89	$ 22	$ 23
Interest cost	190	221	37	47
Expected return on assets	(317)	(306)	(41)	(38)
Amortization of:				
Prior service cost (benefit)	1	—	(30)	(45)
Actuarial loss	128	104	12	11
Settlement charges	8	7	—	—
Contractual termination benefits	—	1	—	—
Net periodic benefit cost	$ 107	$ 116	$ —	$ (2)

	Pension Benefits Nine Months Ended September 30,		OPEB Nine Months Ended September 30,	
	2020	2019	2020	2019
Components of net periodic benefit cost:				
Service cost	$ 290	$ 267	$ 67	$ 70
Interest cost	569	663	114	141
Expected return on assets	(953)	(918)	(122)	(115)
Amortization of:				
Prior service cost (benefit)	3	—	(92)	(134)
Actuarial loss	384	310	36	34
Settlement charges	14	7	—	—
Contractual termination benefits	—	1	—	—
Net periodic benefit cost	$ 307	$ 330	$ 3	$ (4)

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

The amounts below represent the Registrants' allocated pension and OPEB plan costs. For Exelon, the service cost component is included in Operating and maintenance expense and Property, plant, and equipment, net while the non-service cost components are included in Other, net and Regulatory assets. For Generation and the Utility Registrants, the service cost and non-service cost components are included in Operating and maintenance expense and Property, plant, and equipment, net in their consolidated financial statements.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Pension and OPEB Costs	**2020**	**2019**	**2020**	**2019**
Exelon	$ 107	$ 114	$ 310	$ 326
Generation	30	37	89	100
ComEd	29	23	85	70
PECO	1	4	4	9
BGE	16	16	47	47
PHI	17	23	52	71
Pepco	4	6	11	19
DPL	2	4	6	11
ACE	3	4	10	12

Defined Contribution Savings Plans

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the three and nine months ended September 30, 2020 and 2019, respectively.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Savings Plan Matching Contributions	**2020**	**2019**	**2020**	**2019**
Exelon	$ 37	$ 36	$ 104	$ 101
Generation	14	14	41	41
ComEd	9	9	25	26
PECO	3	2	8	7
BGE	4	4	8	9
PHI	3	4	9	8
Pepco	1	1	3	2
DPL	1	1	2	2
ACE	—	1	1	1

11. Derivative Financial Instruments (All Registrants)

The Registrants use derivative instruments to manage commodity price risk, interest rate risk, and foreign exchange risk related to ongoing business operations.

Authoritative guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings immediately. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include NPNS, cash flow hedges, and fair value hedges. All derivative economic hedges related to commodities, referred to as economic hedges, are recorded at fair value through earnings at Generation and are offset by a corresponding regulatory asset or liability at ComEd. For all NPNS derivative instruments, accounts receivable or accounts payable are recorded when derivative settles and revenue or expense is recognized in earnings as the underlying physical commodity is sold or consumed.

Authoritative guidance about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Combined Notes to Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheets. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. In the tables below that present fair value balances, Generation's energy-related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including margin on exchange positions, is aggregated in the collateral and netting columns.

Generation's and ComEd's use of cash collateral is generally unrestricted unless Generation or ComEd are downgraded below investment grade. Cash collateral held by PECO, BGE, Pepco, DPL, and ACE must be deposited in an unaffiliated major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

Commodity Price Risk (All Registrants)

Each of the Registrants employ established policies and procedures to manage their risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, including swaps, futures, forwards, options, and short-term and long-term commitments to purchase and sell energy and commodity products. The Registrants believe these instruments, which are either determined to be non-derivative or classified as economic hedges, mitigate exposure to fluctuations in commodity prices.

Generation. To the extent the amount of energy Generation produces differs from the amount of energy it has contracted to sell, Exelon and Generation are exposed to market fluctuations in the prices of electricity, fossil fuels, and other commodities. Within Exelon, Generation has the most exposure to commodity price risk. As such, Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power and gas sales, fuel and power purchases, natural gas transportation and pipeline capacity agreements, and other energy-related products marketed and purchased. To manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from expected sales of power and gas and purchases of power and fuel. The objectives for executing such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall energy marketing activities and are subject to limits established by Exelon's RMC.

Utility Registrants. The Utility Registrants procure electric and natural gas supply through a competitive procurement process approved by each of the respective state utility commissions. The Utility Registrants' hedging programs are intended to reduce exposure to energy and natural gas price volatility and have no direct earnings impact as the costs are fully recovered from customers through regulatory-approved recovery mechanisms. The following table provides a summary of the Utility Registrants' primary derivative hedging instruments, listed by commodity and accounting treatment.

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

Registrant	Commodity	Accounting Treatment	Hedging instrument
ComEd	Electricity	NPNS	Fixed price contracts based on all requirements in the IPA procurement plans.
	Electricity	Changes in fair value of economic hedge recorded to an offsetting regulatory asset or liability[(a)]	20-year floating-to-fixed energy swap contracts beginning June 2012 based on the renewable energy resource procurement requirements in the Illinois Settlement Legislation of approximately 1.3 million MWhs per year.
PECO[(b)]	Gas	NPNS	Fixed price contracts to cover about 15% of planned natural gas purchases in support of projected firm sales.
BGE	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
	Gas	NPNS	Fixed price contracts for between 10-20% of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period.
Pepco	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
DPL	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
	Gas	NPNS	Fixed and Index priced contracts through full requirements contracts.
		Changes in fair value of economic hedge recorded to an offsetting regulatory asset or liability[(c)]	Exchange traded future contracts for 50% of estimated monthly purchase requirements each month, including purchases for storage injections.
ACE	Electricity	NPNS	Fixed price contracts for all BGS requirements through full requirements contracts.

____
(a) See Note 3 - Regulatory Matters of the 2019 Form 10-K for additional information.
(b) As part of its hedging program, PECO enters into electric supply procurement contracts that do not meet the definition of a derivative instrument.
(c) The fair value of the DPL economic hedge is not material as of September 30, 2020 and December 31, 2019 and is not presented in the fair value tables below.

The following table provides a summary of the derivative fair value balances recorded by Exelon, Generation, and ComEd as of September 30, 2020 and December 31, 2019:

September 30, 2020	Exelon	Generation					ComEd
Derivatives	Total Derivatives	Economic Hedges	Proprietary Trading	Collateral[(a)(b)]	Netting[(a)]	Subtotal	Economic Hedges
Mark-to-market derivative assets (current assets)	$ 471	$ 2,566	$ 58	$ 79	$ (2,232)	$ 471	$ —
Mark-to-market derivative assets (noncurrent assets)	383	1,500	16	39	(1,172)	383	—
Total mark-to-market derivative assets	854	4,066	74	118	(3,404)	854	—
Mark-to-market derivative liabilities (current liabilities)	(168)	(2,414)	(40)	84	2,232	(138)	(30)
Mark-to-market derivative liabilities (noncurrent liabilities)	(378)	(1,313)	(12)	49	1,172	(104)	(274)
Total mark-to-market derivative liabilities	(546)	(3,727)	(52)	133	3,404	(242)	(304)
Total mark-to-market derivative net assets (liabilities)	$ 308	$ 339	$ 22	$ 251	$ —	$ 612	$ (304)

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

December 31, 2019	Exelon	Generation					ComEd
Description	Total Derivatives	Economic Hedges	Proprietary Trading	Collateral[(a)(b)]	Netting[(a)]	Subtotal	Economic Hedges
Mark-to-market derivative assets (current assets)	$ 675	$ 3,506	$ 72	$ 287	$ (3,190)	$ 675	$ —
Mark-to-market derivative assets (noncurrent assets)	508	1,238	25	122	(877)	508	—
Total mark-to-market derivative assets	1,183	4,744	97	409	(4,067)	1,183	—
Mark-to-market derivative liabilities (current liabilities)	(236)	(3,713)	(38)	357	3,190	(204)	(32)
Mark-to-market derivative liabilities (noncurrent liabilities)	(380)	(1,140)	(11)	163	877	(111)	(269)
Total mark-to-market derivative liabilities	(616)	(4,853)	(49)	520	4,067	(315)	(301)
Total mark-to-market derivative net assets (liabilities)	$ 567	$ (109)	$ 48	$ 929	$ —	$ 868	$ (301)

(a) Exelon and Generation net all available amounts allowed under the derivative authoritative guidance in the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These amounts are not material and not reflected in the table above.
(b) Of the collateral posted/(received), $34 million and $511 million represents variation margin on the exchanges at September 30, 2020 and December 31, 2019 respectively.

Economic Hedges (Commodity Price Risk)

Generation. For the three and nine months ended September 30, 2020 and 2019, Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses) which are also located in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Income Statement Location	Gain (Loss)		Gain (Loss)	
Operating revenues	$ 39	$ 76	$ 238	$ 65
Purchased power and fuel	209	(45)	224	(127)
Total Exelon and Generation	$ 248	$ 31	$ 462	$ (62)

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation’s owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of September 30, 2020, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 97%-100% and 87%-90% for 2020 and 2021, respectively.

Proprietary Trading (Commodity Price Risk)

Generation also executes commodity derivatives for proprietary trading purposes. Proprietary trading includes all contracts executed with the intent of benefiting from shifts or changes in market prices as opposed to those executed with the intent of hedging or managing risk. Gains and losses associated with proprietary trading are reported as Operating revenues in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income and are included in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows. For the three and nine months ended September 30, 2020 and 2019, net pre-tax commodity mark-to-market gains and losses for Exelon and Generation were not material. The Utility Registrants do not execute derivatives for proprietary trading purposes.

Interest Rate and Foreign Exchange Risk (Exelon and Generation)

Exelon and Generation utilize interest rate swaps, which are treated as economic hedges, to manage their interest rate exposure. On July 1, 2018, Exelon de-designated its fair value hedges related to interest rate risk and Generation de-designated its cash flow hedges related to interest rate risk. The notional amounts were $1,217 million and $1,269 million at September 30, 2020 and December 31, 2019, respectively, for Exelon and $517 million and $569 million at September 30, 2020 and December 31, 2019, respectively, for Generation.

Generation utilizes foreign currency derivatives to manage foreign exchange rate exposure associated with international commodity purchases in currencies other than U.S. dollars, which are treated as economic hedges. The notional amounts were $171 million and $231 million at September 30, 2020 and December 31, 2019, respectively.

The mark-to-market derivative assets and liabilities as of September 30, 2020 and December 31, 2019 and the mark-to-market gains and losses for the three and nine months ended September 30, 2020 and 2019 were not material for Exelon and Generation.

Credit Risk (All Registrants)

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

Generation. For commodity derivatives, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation’s exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a 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.

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

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 September 30, 2020. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below exclude credit risk exposure from individual retail counterparties, nuclear fuel procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE, NASDAQ, NGX, and Nodal commodity exchanges.

Rating as of September 30, 2020	Total Exposure Before Credit Collateral	Credit Collateral[(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 638	$ 27	$ 611	—	$ —
Non-investment grade	4	—	4		
No external ratings					
Internally rated — investment grade	168	1	167		
Internally rated — non-investment grade	110	29	81		
Total	$ 920	$ 57	$ 863	—	$ —

Net Credit Exposure by Type of Counterparty	As of September 30, 2020
Financial institutions	$ 26
Investor-owned utilities, marketers, power producers	650
Energy cooperatives and municipalities	142
Other	45
Total	$ 863

(a) As of September 30, 2020, credit collateral held from counterparties where Generation had credit exposure included $31 million of cash and $26 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 September 30, 2020, the Utility Registrants' counterparty credit risk with suppliers was not material.

Credit-Risk-Related Contingent Features (All Registrants)

Generation. As part of the normal course of business, Generation routinely enters into physically or financially settled contracts for the purchase and sale of electric capacity, electricity, fuels, emissions allowances, and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges where the exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

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

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	September 30, 2020	December 31, 2019
Gross fair value of derivative contracts containing this feature[(a)]	$ (750)	$ (956)
Offsetting fair value of in-the-money contracts under master netting arrangements[(b)]	535	649
Net fair value of derivative contracts containing this feature[(c)]	$ (215)	$ (307)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk related contingent features ignoring the effects of master netting agreements.
(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.
(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

As of September 30, 2020 and December 31, 2019, Exelon and Generation posted or held the following amounts of cash collateral and letters of credit on derivative contracts with external counterparties, after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

	September 30, 2020	December 31, 2019
Cash collateral posted	$ 288	$ 982
Letters of credit posted	212	264
Cash collateral held	68	103
Letters of credit held	74	112
Additional collateral required in the event of a credit downgrade below investment grade	1,287	1,509

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded.

Utility Registrants

The Utility Registrants' electric supply procurement contracts do not contain provisions that would require them to post collateral.

PECO's, BGE's, and DPL's natural gas procurement contracts contain provisions that could require PECO, BGE, and DPL to post collateral in the form of cash or credit support, which vary by contract and counterparty, with thresholds contingent upon PECO's, BGE, and DPL's credit rating. As of September 30, 2020, PECO, BGE, and DPL were not required to post collateral for any of these agreements. If PECO, BGE, or DPL lost their investment grade credit ratings as of September 30, 2020, they could have been required to post incremental collateral to its counterparties of $22 million, $31 million and $10 million, respectively.

12. Debt and Credit Agreements (All Registrants)

Short-Term Borrowings

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

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

Commercial Paper

The following table reflects the Registrants' commercial paper programs as of September 30, 2020 and December 31, 2019. PECO had no commercial paper borrowings as of both September 30, 2020 and December 31, 2019.

	Outstanding Commercial Paper as of		Average Interest Rate on Commercial Paper Borrowings as of	
Commercial Paper Issuer	**September 30, 2020**	**December 31, 2019**	**September 30, 2020**	**December 31, 2019**
Exelon[(a)]	$ 141	$ 870	0.16 %	2.25 %
Generation	—	320	— %	1.84 %
ComEd	141	130	0.16 %	2.38 %
BGE	—	76	— %	2.46 %
PHI[(b)]	—	208	— %	N/A
PEPCO	—	82	— %	2.56 %
DPL	—	56	— %	2.02 %
ACE	—	70	— %	2.43 %

____
(a) Includes outstanding commercial paper at Exelon Corporate of $136 million with average interest rates on commercial paper borrowings of 1.92% at December 31, 2019. Exelon Corporate had no outstanding commercial paper borrowings as of September 30, 2020.
(b) Includes the consolidated amounts of Pepco, DPL, and ACE.

On March 19, 2020, Generation borrowed $1.5 billion on its revolving credit facility due to disruptions in the commercial paper markets as a result of COVID-19. The funds were used to refinance commercial paper. Generation repaid the $1.5 billion borrowed on the revolving credit facility on April 3, 2020. As of September 30, 2020, the available capacity on Generation’s revolving credit facility was $4.9 billion. See Note 16— Debt and Credit Agreements of the Exelon 2019 Form 10-K for additional information on the Registrants’ credit facilities.

Short-Term Loan Agreements

On March 23, 2017, Exelon Corporate entered into a term loan agreement for $500 million. The loan agreement was renewed on March 19, 2020 and will expire on March 18, 2021. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.65% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's Consolidated Balance Sheet within Short-term borrowings.

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

On March 31, 2020, Generation entered into a term loan agreement for $300 million. The loan agreement has an expiration of March 30, 2021. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.75% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Generation's Consolidated Balance Sheet within Short-term borrowings.

Revolving Credit Agreements

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

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

Bilateral Credit Agreements

On May 15, 2020, Generation entered into a credit agreement establishing a $100 million bilateral credit facility. This facility will solely be used by Generation to issue letters of credit, and the maturity date is automatically renewed based on the contingency standards set within the agreement.

During the second and third quarters of 2020, CENG drew on its bilateral credit facility. As of September 30, 2020, there was $40 million outstanding at this facility. The bilateral credit facility with CENG is incorporated within Generation, and supports the issuance of letters of credit and funding for working capital.

Long-Term Debt

Issuance of Long-Term Debt

During the nine months ended September 30, 2020, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Notes	4.05 %	April 15, 2030	$ 1,250	Repay existing indebtedness and for general corporate purposes.
Exelon	Notes	4.70 %	April 15, 2050	750	Repay existing indebtedness and for general corporate purposes.
Generation	Senior Notes	3.25 %	June 1, 2025	900	Repay existing indebtedness and for general corporate purposes.
Generation	Energy Efficiency Project Financing[(a)]	3.95 %	December 31, 2020	3	Funding to install energy conservation measures for the Fort Meade project.
Generation	Energy Efficiency Project Financing[(a)]	2.53 %	April 30, 2021	2	Funding to install energy conservation measures for the Fort AP Hill project.
ComEd	First Mortgage Bonds, Series 128	2.20 %	March 1, 2030	350	Repay a portion of outstanding commercial paper obligations and fund other general corporate purposes.
ComEd	First Mortgage Bonds, Series 129	3.00 %	March 1, 2050	650	Repay a portion of outstanding commercial paper obligations and to fund 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[(b)]	Tax-Exempt Bonds	1.05 %	January 1, 2031	78	Refinance existing indebtedness.
ACE	Tax-Exempt First Mortgage Bonds	2.25 %	June 1, 2029	23	Refinance existing indebtedness.
ACE	First Mortgage Bonds	3.24 %	June 9, 2050	100	Repay existing indebtedness and for general corporate purposes.

____
(a) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.
(b) The bonds have a 1.05% interest rate through July 2025.

Debt Covenants

As of September 30, 2020, the Registrants are in compliance with debt covenants.

Nonrecourse Debt

Exelon and Generation have issued nonrecourse debt financing. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against Exelon or Generation in the event of a default.

Antelope Valley Solar Ranch One. In December 2011, the DOE Loan Programs Office issued a guarantee for up to $646 million for a nonrecourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project became fully operational in 2014. The loan will mature on January 5, 2037. As of September 30, 2020, approximately $470 million was outstanding. In addition, Generation has issued letters of credit to support its equity investment in the project. As of September 30, 2020, Generation had $37 million in letters of credit outstanding related to the project. In 2017, Generation's interests in Antelope Valley were also contributed to and are pledged as collateral for the EGR IV financing structure referenced below.

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

The United States Bankruptcy Court entered an order on June 20, 2020 confirming PG&E's plan of reorganization. On July 1, 2020 the plan became effective, and PG&E emerged from bankruptcy. On July 21, 2020, Antelope Valley received a waiver from the DOE for the event of default and, as such, distributions from Antelope Valley to EGR IV were permitted and the debt was classified as noncurrent as of June 30, 2020. The debt continues to be presented as noncurrent as of September 30, 2020.

See Note 8 — Asset Impairments for additional information.

ExGen Renewables IV. In November 2017, EGR IV, an indirect subsidiary of Exelon and Generation, entered into an $850 million nonrecourse senior secured term loan credit facility agreement. Generation's interests in EGRP, Antelope Valley, SolGen, and Albany Green Energy were all contributed to and are pledged as collateral for this financing. The loan is scheduled to mature on November 28, 2024. As of September 30, 2020, approximately $710 million was outstanding.

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

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

13. Fair Value of Financial Assets and Liabilities (All Registrants)

Exelon measures and classifies fair value measurements in accordance with the hierarchy as defined by GAAP. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 - quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to liquidate as of the reporting date.
- Level 2 - inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3 - unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Fair Value of Financial Liabilities Recorded at Amortized Cost

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of September 30, 2020 and December 31, 2019. The Registrants have no financial liabilities classified as Level 1.

The carrying amounts of the Registrants' short-term liabilities as presented on their Consolidated Balance Sheets are representative of their fair value (Level 2) because of the short-term nature of these instruments.

	September 30, 2020				December 31, 2019			
	Carrying Amount	Fair Value			Carrying Amount	Fair Value		
		Level 2	Level 3	Total		Level 2	Level 3	Total
Long-Term Debt, including amounts due within one year[(a)]								
Exelon	$ 37,589	$ 40,816	$ 3,237	$ 44,053	$ 36,039	$ 37,453	$ 2,580	$ 40,033
Generation	6,756	6,250	1,401	7,651	7,974	7,304	1,366	8,670
ComEd	8,981	10,970	—	10,970	8,491	9,848	—	9,848
PECO	3,753	4,498	50	4,548	3,405	3,868	50	3,918
BGE	3,664	4,263	—	4,263	3,270	3,649	—	3,649
PHI	7,020	6,082	1,786	7,868	6,563	5,902	1,164	7,066
Pepco	3,164	3,343	739	4,082	2,864	3,198	388	3,586
DPL	1,676	1,463	449	1,912	1,567	1,408	311	1,719
ACE	1,417	1,017	598	1,615	1,327	1,026	464	1,490
Long-Term Debt to Financing Trusts[(a)]								
Exelon	$ 390	$ —	$ 467	$ 467	$ 390	$ —	$ 428	$ 428
ComEd	205	—	246	246	205	—	227	227
PECO	184	—	221	221	184	—	201	201
SNF Obligation								
Exelon	$ 1,207	$ 1,042	$ —	$ 1,042	$ 1,199	$ 1,055	$ —	$ 1,055
Generation	1,207	1,042	—	1,042	1,199	1,055	—	1,055

(a) Includes unamortized debt issuance costs which are not fair valued.

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

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 September 30, 2020 and December 31, 2019:

Exelon and Generation

	Exelon					Generation				
As of September 30, 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]	$ 1,687	$ —	$ —	$ —	$ 1,687	$ 270	$ —	$ —	$ —	$ 270
NDT fund investments										
Cash equivalents[b]	313	91	—	—	404	313	91	—	—	404
Equities	3,345	1,794	—	1,370	6,509	3,345	1,794	—	1,370	6,509
Fixed income										
Corporate debt	—	1,516	280	—	1,796	—	1,516	280	—	1,796
U.S. Treasury and agencies	1,843	137	—	—	1,980	1,843	137	—	—	1,980
Foreign governments	—	52	—	—	52	—	52	—	—	52
State and municipal debt	—	104	—	—	104	—	104	—	—	104
Other	—	40	—	1,010	1,050	—	40	—	1,010	1,050
Fixed income subtotal	1,843	1,849	280	1,010	4,982	1,843	1,849	280	1,010	4,982
Private credit	—	—	238	533	771	—	—	238	533	771
Private equity	—	—	—	439	439	—	—	—	439	439
Real estate	—	—	—	650	650	—	—	—	650	650
NDT fund investments subtotal[c][d]	5,501	3,734	518	4,002	13,755	5,501	3,734	518	4,002	13,755
Rabbi trust investments										
Cash equivalents	58	—	—	—	58	4	—	—	—	4
Mutual funds	88	—	—	—	88	28	—	—	—	28
Fixed income	—	11	—	—	11	—	—	—	—	—
Life insurance contracts	—	84	34	—	118	—	27	—	—	27
Rabbi trust investments subtotal	146	95	34	—	275	32	27	—	—	59
Commodity derivative assets										
Economic hedges	776	1,737	1,553	—	4,066	776	1,737	1,553	—	4,066
Proprietary trading	—	37	37	—	74	—	37	37	—	74
Effect of netting and allocation of collateral[e][f]	(656)	(1,594)	(1,036)	—	(3,286)	(656)	(1,594)	(1,036)	—	(3,286)
Commodity derivative assets subtotal	120	180	554	—	854	120	180	554	—	854
DPP consideration	—	732	—	—	732	—	732	—	—	732
Total assets	7,454	4,741	1,106	4,002	17,303	5,923	4,673	1,072	4,002	15,670

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

	Exelon					Generation				
As of September 30, 2020	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Liabilities										
Commodity derivative liabilities										
Economic hedges	(700)	(1,692)	(1,639)	—	(4,031)	(700)	(1,692)	(1,335)	—	(3,727)
Proprietary trading	—	(36)	(16)	—	(52)	—	(36)	(16)	—	(52)
Effect of netting and allocation of collateral[e][f]	699	1,708	1,130	—	3,537	699	1,708	1,130	—	3,537
Commodity derivative liabilities subtotal	(1)	(20)	(525)	—	(546)	(1)	(20)	(221)	—	(242)
Deferred compensation obligation	—	(135)	—	—	(135)	—	(37)	—	—	(37)
Total liabilities	(1)	(155)	(525)	—	(681)	(1)	(57)	(221)	—	(279)
Total net assets	$ 7,453	$ 4,586	$ 581	$ 4,002	$ 16,622	$ 5,922	$ 4,616	$ 851	$ 4,002	$ 15,391

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

	Exelon					Generation				
As of December 31, 2019	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Assets										
Cash equivalents[(a)]	$ 639	$ —	$ —	$ —	$ 639	$ 214	$ —	$ —	$ —	$ 214
NDT fund investments										
Cash equivalents[(b)]	365	87	—	—	452	365	87	—	—	452
Equities	3,353	1,753	—	1,388	6,494	3,353	1,753	—	1,388	6,494
Fixed income										
Corporate debt	—	1,469	257	—	1,726	—	1,469	257	—	1,726
U.S. Treasury and agencies	1,808	131	—	—	1,939	1,808	131	—	—	1,939
Foreign governments	—	42	—	—	42	—	42	—	—	42
State and municipal debt	—	90	—	—	90	—	90	—	—	90
Other	—	33	—	953	986	—	33	—	953	986
Fixed income subtotal	1,808	1,765	257	953	4,783	1,808	1,765	257	953	4,783
Private credit	—	—	254	508	762	—	—	254	508	762
Private equity	—	—	—	402	402	—	—	—	402	402
Real estate	—	—	—	607	607	—	—	—	607	607
NDT fund investments subtotal[(c)(d)]	5,526	3,605	511	3,858	13,500	5,526	3,605	511	3,858	13,500
Rabbi trust investments										
Cash equivalents	50	—	—	—	50	4	—	—	—	4
Mutual funds	81	—	—	—	81	25	—	—	—	25
Fixed income	—	12	—	—	12	—	—	—	—	—
Life insurance contracts	—	78	41	—	119	—	25	—	—	25
Rabbi trust investments subtotal	131	90	41	—	262	29	25	—	—	54
Commodity derivative assets										
Economic hedges	768	2,491	1,485	—	4,744	768	2,491	1,485	—	4,744
Proprietary trading	—	37	60	—	97	—	37	60	—	97
Effect of netting and allocation of collateral[(e)(f)]	(908)	(2,162)	(588)	—	(3,658)	(908)	(2,162)	(588)	—	(3,658)
Commodity derivative assets subtotal	(140)	366	957	—	1,183	(140)	366	957	—	1,183
Total assets	6,156	4,061	1,509	3,858	15,584	5,629	3,996	1,468	3,858	14,951

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

	Exelon					Generation				
As of December 31, 2019	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Liabilities										
Commodity derivative liabilities										
Economic hedges	(1,071)	(2,855)	(1,228)	—	(5,154)	(1,071)	(2,855)	(927)	—	(4,853)
Proprietary trading	—	(34)	(15)	—	(49)	—	(34)	(15)	—	(49)
Effect of netting and allocation of collateral[(e)(f)]	1,071	2,714	802	—	4,587	1,071	2,714	802	—	4,587
Commodity derivative liabilities subtotal	—	(175)	(441)	—	(616)	—	(175)	(140)	—	(315)
Deferred compensation obligation	—	(147)	—	—	(147)	—	(41)	—	—	(41)
Total liabilities	—	(322)	(441)	—	(763)	—	(216)	(140)	—	(356)
Total net assets	$ 6,156	$ 3,739	$ 1,068	$ 3,858	$ 14,821	$ 5,629	$ 3,780	$ 1,328	$ 3,858	$ 14,595

____

(a) Exelon excludes cash of $677 million and $373 million at September 30, 2020 and December 31, 2019, respectively, and restricted cash of $116 million and $110 million at September 30, 2020 and December 31, 2019, respectively, and includes long-term restricted cash of $137 million and $177 million at September 30, 2020 and December 31, 2019, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. Generation excludes cash of $408 million and $177 million at September 30, 2020 and December 31, 2019, respectively, and restricted cash of $45 million and $58 million at September 30, 2020 and December 31, 2019, respectively.
(b) Includes $121 million and $90 million of cash received from outstanding repurchase agreements at September 30, 2020 and December 31, 2019, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (d) below.
(c) Includes derivative assets of less than $1 million and $2 million, which have total notional amounts of $658 million and $724 million at September 30, 2020 and December 31, 2019, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the periods ended and do not represent the amount of Exelon and Generation's exposure to credit or market loss.
(d) Excludes net liabilities of $208 million and $147 million at September 30, 2020 and December 31, 2019, respectively, which include certain derivative assets that have notional amounts of $153 million and $99 million at September 30, 2020 and December 31, 2019, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.
(e) Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled $43 million, $114 million, and $94 million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of September 30, 2020. Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled $163 million, $551 million, and $214 million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of December 31, 2019.
(f) Of the collateral posted/(received), $34 million and $511 million represents variation margin on the exchanges as of September 30, 2020 and December 31, 2019, respectively.

As of September 30, 2020, Exelon and Generation have outstanding commitments to invest in fixed income, private credit, private equity and real estate investments of approximately $52 million, $119 million, $299 million, and $395 million, respectively. These commitments will be funded by Generation's existing NDT funds.

Exelon and Generation hold investments without readily determinable fair values with carrying amounts of $76 million and $66 million as of September 30, 2020, respectively. Changes in fair value, cumulative adjustments, and impairments were not material for the three and nine months ended September 30, 2020.

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

ComEd, PECO and BGE

	ComEd				PECO				BGE			
As of September 30, 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)]	$ 396	$ —	$ —	$ 396	$ 184	$ —	$ —	$ 184	$ 298	$ —	$ —	$ 298
Rabbi trust investments												
Mutual funds	—	—	—	—	9	—	—	9	9	—	—	9
Life insurance contracts	—	—	—	—	—	13	—	13	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	9	13	—	22	9	—	—	9
Total assets	396	—	—	396	193	13	—	206	307	—	—	307
Liabilities												
Deferred compensation obligation	—	(7)	—	(7)	—	(8)	—	(8)	—	(5)	—	(5)
Mark-to-market derivative liabilities[(b)]	—	—	(304)	(304)	—	—	—	—	—	—	—	—
Total liabilities	—	(7)	(304)	(311)	—	(8)	—	(8)	—	(5)	—	(5)
Total net assets (liabilities)	$ 396	$ (7)	$ (304)	$ 85	$ 193	$ 5	$ —	$ 198	$ 307	$ (5)	$ —	$ 302

	ComEd				PECO				BGE			
As of December 31, 2019	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents[(a)]	$ 280	$ —	$ —	$ 280	$ 15	$ —	$ —	$ 15	$ —	$ —	$ —	$ —
Rabbi trust investments												
Mutual funds	—	—	—	—	8	—	—	8	8	—	—	8
Life insurance contracts	—	—	—	—	—	11	—	11	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	8	11	—	19	8	—	—	8
Total assets	280	—	—	280	23	11	—	34	8	—	—	8
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(9)	—	(9)	—	(5)	—	(5)
Mark-to-market derivative liabilities[(b)]	—	—	(301)	(301)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(301)	(309)	—	(9)	—	(9)	—	(5)	—	(5)
Total net assets (liabilities)	$ 280	$ (8)	$ (301)	$ (29)	$ 23	$ 2	$ —	$ 25	$ 8	$ (5)	$ —	$ 3

(a) ComEd excludes cash of $76 million and $90 million at September 30, 2020 and December 31, 2019, respectively, and restricted cash of $36 million and $33 million at September 30, 2020 and December 31, 2019, respectively, and includes long-term restricted cash of $127 million and $163 million at September 30, 2020 and December 31, 2019, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. PECO excludes cash of $65 million and $12 million at September 30, 2020 and December 31, 2019, respectively. BGE excludes cash of $28 million and $24 million at September 30, 2020 and December 31, 2019, respectively, and restricted cash of $1 million at both September 30, 2020 and December 31, 2019.

(b) The Level 3 balance consists of the current and noncurrent liability of $30 million and $274 million, respectively, at September 30, 2020 and $32 million and $269 million, respectively, at December 31, 2019 related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

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

PHI, Pepco, DPL and ACE

	As of September 30, 2020				As of December 31, 2019			
PHI	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents[(a)]	$ 166	$ —	$ —	$ 166	$ 124	$ —	$ —	$ 124
Rabbi trust investments								
Cash equivalents	52	—	—	52	44	—	—	44
Mutual funds	14	—	—	14	14	—	—	14
Fixed income	—	11	—	11	—	12	—	12
Life insurance contracts	—	26	34	60	—	24	41	65
Rabbi trust investments subtotal	66	37	34	137	58	36	41	135
Total assets	232	37	34	303	182	36	41	259
Liabilities								
Deferred compensation obligation	—	(17)	—	(17)	—	(19)	—	(19)
Total liabilities	—	(17)	—	(17)	—	(19)	—	(19)
Total net assets	$ 232	$ 20	$ 34	$ 286	$ 182	$ 17	$ 41	$ 240

	Pepco				DPL				ACE			
As of September 30, 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)]	$ 112	$ —	$ —	$ 112	$ 17	$ —	$ —	$ 17	$ 14	$ —	$ —	$ 14
Rabbi trust investments												
Cash equivalents	51	—	—	51	—	—	—	—	—	—	—	—
Fixed income	—	2	—	2	—	—	—	—	—	—	—	—
Life insurance contracts	—	26	34	60	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	51	28	34	113	—	—	—	—	—	—	—	—
Total assets	163	28	34	225	17	—	—	17	14	—	—	14
Liabilities												
Deferred compensation obligation	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total liabilities	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total net assets	$ 163	$ 26	$ 34	$ 223	$ 17	$ —	$ —	$ 17	$ 14	$ —	$ —	$ 14

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

	Pepco				DPL				ACE			
As of December 31, 2019	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents[(a)]	$ 34	$ —	$ —	$ 34	$ —	$ —	$ —	$ —	$ 16	$ —	$ —	$ 16
Rabbi trust investments												
Cash equivalents	43	—	—	43	—	—	—	—	—	—	—	—
Fixed income	—	2	—	2	—	—	—	—	—	—	—	—
Life insurance contracts	—	24	41	65	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	43	26	41	110	—	—	—	—	—	—	—	—
Total assets	77	26	41	144	—	—	—	—	16	—	—	16
Liabilities												
Deferred compensation obligation	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total liabilities	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total net assets (liabilities)	$ 77	$ 24	$ 41	$ 142	$ —	$ —	$ —	$ —	$ 16	$ —	$ —	$ 16

____

(a) PHI excludes cash of $78 million and $57 million at September 30, 2020 and December 31, 2019, respectively, and includes long-term restricted cash of $10 million and $14 million at September 30, 2020 and December 31, 2019, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. Pepco excludes cash of $46 million and $29 million at September 30, 2020 and December 31, 2019, respectively. DPL excludes cash of $9 million and $13 million at September 30, 2020 and December 31, 2019, respectively. ACE excludes cash of $13 million and $12 million at September 30, 2020 and December 31, 2019, respectively, and includes long-term restricted cash of $10 million and $14 million at September 30, 2020 and December 31, 2019, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets.

Reconciliation of Level 3 Assets and Liabilities

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2020 and 2019:

	Exelon	Generation			ComEd	PHI and Pepco	
Three Months Ended September 30, 2020	**Total**	**NDT Fund Investments**	**Mark-to-Market Derivatives**	**Total Generation**	**Mark-to-Market Derivatives**	**Life Insurance Contracts**	**Eliminated in Consolidation**
Balance as of June 30, 2020	$ 883	$ 499	$ 659	$ 1,158	$ (318)	$ 43	$ —
Total realized / unrealized gains (losses)							
Included in net income	(327)	3	(318) [(a)]	(315)	—	(12)	—
Included in noncurrent payables to affiliates	—	18	—	18	—	—	(18)
Included in regulatory assets/liabilities	32	—	—	—	14 [(b)]	—	18
Change in collateral	(79)	—	(79)	(79)	—	—	—
Purchases, sales, issuances and settlements							
Purchases	66	1	65	66	—	—	—
Sales	(3)	—	(3)	(3)	—	—	—
Settlements	—	(3)	—	(3)	—	3	—
Transfers out of Level 3	9	—	9 [(c)]	9	—	—	—
Balance at September 30, 2020	$ 581	$ 518	$ 333	$ 851	$ (304)	$ 34	$ —
The amount of total (losses) gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2020	$ (222)	$ 3	$ (213)	$ (210)	$ —	$ (12)	$ —

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

Table of Contents

	Exelon	Generation			ComEd	PHI and Pepco	
Nine months ended September 30, 2020	Total	NDT Fund Investments	Mark-to-Market Derivatives	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	Eliminated in Consolidation
Balance as of December 31, 2019	$ 1,068	$ 511	$ 817	$ 1,328	$ (301)	$ 41	$ —
Total realized / unrealized gains (losses)							
Included in net income	(483)	1	(474) (a)	(473)	—	(10)	—
Included in noncurrent payables to affiliates	—	17	—	17	—	—	(17)
Included in regulatory assets	14	—	—	—	(3) (b)	—	17
Change in collateral	(120)	—	(120)	(120)	—	—	—
Purchases, sales, issuances and settlements							
Purchases	136	6	130	136	—	—	—
Sales	(27)	—	(27)	(27)	—	—	—
Settlements	(15)	(18)	—	(18)	—	3	—
Transfers into Level 3	(5)	1	(6) (c)	(5)	—	—	—
Transfers out of Level 3	13	—	13 (c)	13	—	—	—
Balance as of September 30, 2020	$ 581	$ 518	$ 333	$ 851	$ (304)	$ 34	$ —
The amount of total (losses) gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2020	$ (107)	$ 1	$ (98)	$ (97)	$ —	$ (10)	$ —

	Exelon	Generation			ComEd	PHI and Pepco	
Three Months Ended September 30, 2019	Total	NDT Fund Investments	Mark-to-Market Derivatives	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	Eliminated in Consolidation
Balance as of June 30, 2019	$ 1,179	$ 539	$ 873	$ 1,412	$ (273)	$ 40	$ —
Total realized / unrealized gains (losses)							
Included in net income	(171)	2	(173) (a)	(171)	—	—	—
Included in noncurrent payables to affiliates	—	11	—	11	—	—	(11)
Included in regulatory assets	4	—	—	—	(7) (b)	—	11
Change in collateral	41	—	41	41	—	—	—
Purchases, sales, issuances and settlements							
Purchases	53	1	52	53	—	—	—
Sales	(22)	(21)	(1)	(22)	—	—	—
Settlements	(18)	(18)	—	(18)	—	—	—
Transfers into Level 3	1	—	1 (c)	1	—	—	—
Transfers out of Level 3	(11)	—	(11) (c)	(11)	—	—	—
Balance as of September 30, 2019	$ 1,056	$ 514	$ 782	$ 1,296	$ (280)	$ 40	$ —
The amount of total (losses) gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2019	$ (18)	$ 2	$ (20)	$ (18)	$ —	$ —	$ —

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

	Exelon	Generation			ComEd	PHI and Pepco	
Nine Months Ended September 30, 2019	Total	NDT Fund Investments	Mark-to-Market Derivatives	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	Eliminated in Consolidation
Balance as of December 31, 2018	$ 907	$ 543	$ 575	$ 1,118	$ (249)	$ 38	$ —
Total realized / unrealized gains (losses)							
Included in net income	(125)	5	(132) (a)	(127)	—	2	—
Included in noncurrent payables to affiliates	—	32	—	32	—	—	(32)
Included in regulatory assets	1	—	—	—	(31) (b)	—	32
Change in collateral	227	—	227	227	—	—	—
Purchases, sales, issuances and settlements							
Purchases	163	43	120	163	—	—	—
Sales	(23)	(21)	(2)	(23)	—	—	—
Settlements	(88)	(88)	—	(88)	—	—	—
Transfers into Level 3	5	—	5 (c)	5	—	—	—
Transfers out of Level 3	(11)	—	(11) (c)	(11)	—	—	—
Balance as of September 30, 2019	$ 1,056	$ 514	$ 782	$ 1,296	$ (280)	$ 40	$ —
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2019	$ 173	$ 5	$ 166	$ 171	$ —	$ 2	$ —

____

(a) Includes a reduction for the reclassification of $105 million and $376 million of realized losses due to the settlement of derivative contracts for the three and nine months ended September 30, 2020. Includes a reduction for the reclassification of $153 million and $298 million of realized losses due to the settlement of derivative contracts for the three and nine months ended September 30, 2019.
(b) Includes 1) an increase in fair value of $9 million for the three months ended September 30, 2020 and a decrease in fair value of $7 million, $26 million, and $31 million for the three months ended September 30, 2019, nine months ended September 30, 2020, and nine months ended September 30, 2019, respectively, and 2) an increase in realized losses recorded in purchased power expense due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers of $5 million, $4 million, $23 million, and $17 million for the three months ended September 30, 2020, three months ended September 30, 2019, nine months ended September 30, 2020, and nine months ended September 30, 2019, respectively.
(c) Transfers into and out of Level 3 generally occur when the contract tenor becomes less and more observable respectively, primarily due to changes in market liquidity or assumptions for certain commodity contracts.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2020 and 2019:

	Exelon				Generation			PHI and Pepco
	Operating Revenues	Purchased Power and Fuel	Operating and Maintenance	Other, net	Operating Revenues	Purchased Power and Fuel	Other, net	Operating and Maintenance
Total realized losses for the three months ended September 30, 2020	$ (305)	$ (13)	$ (12)	$ —	$ (305)	$ (13)	$ —	$ (12)
Total realized losses for the nine months ended September 30, 2020	(370)	(104)	(10)	—	(370)	(104)	—	(10)
Total unrealized (losses) gains for the three months ended September 30, 2020	(216)	3	(12)	3	(216)	3	3	(12)
Total unrealized (losses) gains for the nine months ended September 30, 2020	(50)	(48)	(10)	1	(50)	(48)	1	(10)

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

	Exelon				Generation			PHI and Pepco
	Operating Revenues	Purchased Power and Fuel	Operating and Maintenance	Other, net	Operating Revenues	Purchased Power and Fuel	Other, net	Operating and Maintenance
Total realized (losses) gains for the three months ended September 30, 2019	$ (25)	$ (148)	$ —	$ 2	$ (25)	$ (148)	$ 2	$ —
Total realized gains (losses) for the nine months ended September 30, 2019	122	(254)	—	5	122	(254)	5	—
Total unrealized gains (losses) for the three months ended September 30, 2019	99	(119)	—	2	99	(119)	2	—
Total unrealized gains (losses) gains for the nine months ended September 30, 2019	368	(202)	2	5	368	(202)	5	2

Valuation Techniques Used to Determine Fair Value

Exelon's valuation techniques used to measure the fair value of the assets and liabilities shown in the tables below are in accordance with the policies discussed in Note 17 — Fair Value of Financial Assets and Liabilities of the Exelon 2019 Form 10-K.

Valuation Techniques Used to Determine Net asset Value (Exelon and Generation)

Certain NDT Fund Investments are not classified within the fair value hierarchy and are included under the heading "Not subject to leveling" in the table above. These investments are measured at fair value using NAV per share as a practical expedient and include commingled funds, mutual funds which are not publicly quoted, managed private credit funds, private equity and real estate funds.

For commingled funds and mutual funds, which are not publicly quoted, the fair value is primarily derived from the quoted prices in active markets on the underlying securities and can typically be redeemed monthly with 30 or less days of notice and without further restrictions. For managed private credit funds, the fair value is determined using a combination of valuation models including cost models, market models, and income models and typically cannot be redeemed until maturity of the term loan. Private equity and real estate investments include those in limited partnerships that invest in operating companies and real estate holding companies that are not publicly traded on a stock exchange, such as, leveraged buyouts, growth capital, venture capital, distressed investments, investments in natural resources, and direct investments in pools of real estate properties. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date, which is based on Exelon's understanding of the investment funds. Private equity and real estate valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows, market based comparable data, and independent appraisals from sources with professional qualifications. These valuation inputs are unobservable.

Deferred Purchase Price Consideration (Exelon and Generation)

Exelon and Generation have DPP consideration for the sale of certain receivables of retail electricity at Generation. This amount is valued based on the sales price of the receivables net of allowance for credit losses based on accounts receivable aging historical experience coupled with specific identification through a credit monitoring process, which considers current conditions and forward-looking information such as industry trends, macroeconomic factors, changes in the regulatory environment, external credit ratings, publicly available news, payment status, payment history, and the exercise of collateral calls. Since the DPP consideration is based on the sales price of the receivables, it is categorized as Level 2 in the fair value hierarchy. See Note 5 - Accounts Receivable for additional information on the sale of certain receivables.

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

Mark-to-Market Derivatives (Exelon, Generation and ComEd)

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

Type of trade	Fair Value at September 30, 2020	Fair Value at December 31, 2019	Valuation Technique	Unobservable Input	2020 Range & Arithmetic Average				2019 Range & Arithmetic Average			
Mark-to-market derivatives — Economic Hedges (Exelon and Generation)[(a)(b)]	$ 218	$ 558	Discounted Cash Flow	Forward power price	$9	-	$113	$29	$9	-	$180	$29
				Forward gas price	$1.84	-	$4.69	$2.77	$0.83	-	$10.72	$2.55
			Option Model	Volatility percentage	10%	-	160%	57%	8%	-	236%	70%
Mark-to-market derivatives — Proprietary trading (Exelon and Generation)[(a)(b)]	$ 21	$ 45	Discounted Cash Flow	Forward power price	$9	-	$115	$31	$25	-	$180	$33
Mark-to-market derivatives (Exelon and ComEd)	$ (304)	$ (301)	Discounted Cash Flow	Forward heat rate[(c)]	8x	-	9x	8.85x	9x	-	10x	9.68x
				Marketability reserve	3%	-	8%	4.93%	3%	-	7%	4.95%
				Renewable factor	91%	-	123%	99%	91%	-	123%	99%

____
(a) The valuation techniques, unobservable inputs, ranges and arithmetic averages are the same for the asset and liability positions.
(b) The fair values do not include cash collateral posted on level three positions of $94 million and $214 million as of September 30, 2020 and December 31, 2019, respectively.
(c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.

The inputs listed above, which are as of the balance sheet date, would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation's commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give Generation the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Generation the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

14. Commitments and Contingencies (All Registrants)

The following is an update to the current status of commitments and contingencies set forth in Note 18 of the Exelon 2019 Form 10-K.

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 September 30, 2020:

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

Description	Exelon	PHI	Pepco	DPL	ACE
Total commitments	$ 513	$ 320	$ 120	$ 89	$ 111
Remaining commitments[(a)]	87	69	57	7	5

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

In addition, Exelon is committed to develop or to assist in the commercial development of approximately 37 MWs of new solar generation in Maryland, District of Columbia, and Delaware at an estimated cost of approximately $135 million, which will generate future earnings at Exelon and Generation. Investment costs, which are expected to be primarily capital in nature, are recognized as incurred and recorded in Exelon's and Generation's financial statements. As of September 30, 2020, 27 MWs of new generation were developed and Exelon and Generation have incurred costs of $118 million. Exelon has also committed to purchase 100 MWs of wind energy in PJM. DPL has committed to conducting three RFPs to procure up to a total of 120 MWs of wind RECs for the purpose of meeting Delaware's renewable portfolio standards. DPL has conducted two of the three wind REC RFPs. The first 40 MW wind REC tranche was conducted in 2017 and did not result in a purchase agreement. The second 40 MW wind REC tranche was conducted in 2018 and resulted in a proposed REC purchase agreement that was approved by the DPSC in 2019. The third and final 40 MW wind REC tranche will be conducted in 2022.

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

Commercial Commitments (All Registrants). The Registrants' commercial commitments as of September 30, 2020, representing commitments potentially triggered by future events were as follows:

	Total	Expiration within 2020	2021	2022	2023	2024	2025 and beyond
Exelon							
Letters of credit	$ 1,462	$ 224	$ 1,238	$ —	$ —	$ —	$ —
Surety bonds[(a)]	1,056	388	641	27	—	—	—
Financing trust guarantees	378	—	—	—	—	—	378
Guaranteed lease residual values[(b)]	28	—	2	3	3	6	14
Total commercial commitments	$ 2,924	$ 612	$ 1,881	$ 30	$ 3	$ 6	$ 392
Generation							
Letters of credit	$ 1,447	$ 220	$ 1,227	$ —	$ —	$ —	$ —
Surety bonds[(a)]	912	374	511	27	—	—	—
Total commercial commitments	$ 2,359	$ 594	$ 1,738	$ 27	$ —	$ —	$ —
ComEd							
Letters of credit	$ 7	$ —	$ 7	$ —	$ —	$ —	$ —
Surety bonds[(a)]	16	5	11	—	—	—	—
Financing trust guarantees	200	—	—	—	—	—	200
Total commercial commitments	$ 223	$ 5	$ 18	$ —	$ —	$ —	$ 200
PECO							
Surety bonds[(a)]	$ 2	$ —	$ 2	$ —	$ —	$ —	$ —
Financing trust guarantees	178	—	—	—	—	—	178
Total commercial commitments	$ 180	$ —	$ 2	$ —	$ —	$ —	$ 178
BGE							
Letters of credit	$ 2	$ 2	$ —	$ —	$ —	$ —	$ —
Surety bonds[(a)]	3	1	2	—	—	—	—
Total commercial commitments	$ 5	$ 3	$ 2	$ —	$ —	$ —	$ —
PHI							
Surety bonds[(a)]	$ 21	$ 3	$ 18	$ —	$ —	$ —	$ —
Guaranteed lease residual values[(b)]	28	—	2	3	3	6	14
Total commercial commitments	$ 49	$ 3	$ 20	$ 3	$ 3	$ 6	$ 14
Pepco							
Surety bonds[(a)]	$ 14	$ —	$ 14	$ —	$ —	$ —	$ —
Guaranteed lease residual values[(b)]	9	—	—	1	1	2	5
Total commercial commitments	$ 23	$ —	$ 14	$ 1	$ 1	$ 2	$ 5
DPL							
Surety bonds[(a)]	$ 4	$ 2	$ 2	$ —	$ —	$ —	$ —
Guaranteed lease residual values[(b)]	12	—	1	1	1	3	6
Total commercial commitments	$ 16	$ 2	$ 3	$ 1	$ 1	$ 3	$ 6
ACE							
Surety bonds[(a)]	$ 3	$ 1	$ 2	$ —	$ —	$ —	$ —
Guaranteed lease residual values[(b)]	7	—	1	1	1	1	3
Total commercial commitments	$ 10	$ 1	$ 3	$ 1	$ 1	$ 1	$ 3

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

(b) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The lease term associated with these assets ranges from 1 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $74 million guaranteed by Exelon and PHI, of which $25 million, $31 million, and $18 million is guaranteed by Pepco, DPL, and ACE, respectively. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

Environmental Remediation Matters

General (All Registrants). The Registrants' operations have in the past, and may in the future, require substantial expenditures to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future. Unless otherwise disclosed, the Registrants cannot reasonably estimate whether they will incur significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers. Additional costs could have a material, unfavorable impact on the Registrants' financial statements.

MGP Sites (Exelon and the Utility Registrants). ComEd, PECO, BGE, and DPL have identified sites where former MGP or gas purification activities have or may have resulted in actual site contamination. For almost all of these sites, there are additional PRPs that may share responsibility for the ultimate remediation of each location.

- ComEd has 21 sites that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2025.
- PECO has 8 sites that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 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.

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

As of September 30, 2020 and December 31, 2019, the Registrants had accrued the following undiscounted amounts for environmental liabilities in Other current liabilities and Other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

	September 30, 2020		December 31, 2019	
	Total environmental investigation and remediation liabilities	Portion of total related to MGP investigation and remediation	Total environmental investigation and remediation liabilities	Portion of total related to MGP investigation and remediation
Exelon	$ 494	$ 320	$ 478	$ 320
Generation	125	—	105	—
ComEd	299	298	304	303
PECO	23	22	19	17
BGE	2	—	2	—
PHI	45	—	48	—
Pepco	43	—	46	—
DPL	1	—	1	—
ACE	1	—	1	—

Cotter Corporation (Exelon and Generation). The EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. In 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. Including Cotter, there are three PRPs participating in the West Lake Landfill remediation proceeding. Investigation by Generation has identified a number of other parties who also may be PRPs and could be liable to contribute to the final remedy. Further investigation is ongoing.

In September 2018, the EPA issued its Record of Decision (ROD) Amendment for the selection of a final remedy. The ROD Amendment modified the remedy previously selected by EPA in its 2008 ROD. While the ROD required only that the radiological materials and other wastes at the site be capped, the ROD Amendment requires partial excavation of the radiological materials in addition to the previously selected capping remedy. The ROD Amendment also allows for variation in depths of excavation depending on radiological concentrations. The EPA and the PRPs have entered into a Consent Agreement to perform the Remedial Design, which is expected to be completed by early 2022. In March 2019 the PRPs received Special Notice Letters from the EPA to perform the Remedial Action work. On October 8, 2019, Cotter (Generation's indemnitee) provided a non-binding good faith offer to conduct, or finance, a portion of the remedy, subject to certain conditions. The total estimated cost of the remedy, taking into account the current EPA technical requirements and the total costs expected to be incurred collectively by the PRPs in fully executing the remedy, is approximately $280 million, including cost escalation on an undiscounted basis, which would be allocated among the final group of PRPs. Generation has determined that a loss associated with the EPA's partial excavation and enhanced landfill cover remedy is probable and has recorded a liability included in the table above, that reflects management's best estimate of Cotter's allocable share of the ultimate cost. Given the joint and several nature of this liability, the magnitude of Generation's ultimate liability will depend on the actual costs incurred to implement the required remedy as well as on the nature and terms of any cost-sharing arrangements with the final group of PRPs. Therefore, it is reasonably possible that the ultimate cost and Cotter's associated allocable share could differ significantly once these uncertainties are resolved, which could have a material impact on Exelon's and Generation's future financial statements.

One of the other PRPs has indicated it will be making a contribution claim against Cotter for costs that it has incurred to prevent the subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, Exelon and Generation do not possess sufficient information to assess this claim and therefore are unable to estimate a range of loss, if any. As such, no liability has been recorded for the potential contribution claim. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Exelon's and Generation's financial statements.

In January 2018, the PRPs were advised by the EPA that it will begin an additional investigation and evaluation of groundwater conditions at the West Lake Landfill. In September 2018, the PRPs agreed to an Administrative Settlement Agreement and Order on Consent for the performance by the PRPs of the groundwater Remedial

Investigation (RI)/Feasibility Study (FS). The purpose of this RI/FS is to define the nature and extent of any groundwater contamination from the West Lake Landfill site and evaluate remedial alternatives. Generation estimates the undiscounted cost for the groundwater RI/FS to be approximately $30 million. Generation determined a loss associated with the RI/FS is probable and has recorded a liability included in the table above that reflects management's best estimate of Cotter's allocable share of the cost among the PRPs. At this time Generation cannot predict the likelihood or the extent to which, if any, remediation activities may be required and therefore cannot estimate a reasonably possible range of loss for response costs beyond those associated with the RI/FS component. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Exelon's and Generation's future financial statements.

In August 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's (now Generation's) indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. Government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under FUSRAP. Pursuant to a series of annual agreements since 2011, the DOJ and the PRPs have tolled the statute of limitations until February 28, 2021 so that settlement discussions can proceed. On August 3, 2020, the DOJ advised Cotter and the other PRPs that it is seeking approximately $90 million from all the PRPs and that the PRPs must submit a good faith joint proposed settlement offer by December 1, 2020. Generation has determined that a loss associated with this matter is probable under its indemnification agreement with Cotter and has recorded an estimated liability, which is included in the table above.

Benning Road Site (Exelon, Generation, PHI, and Pepco). In September 2010, PHI received a letter from EPA identifying the Benning Road site as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. A portion of the site was formerly the location of a Pepco Energy Services electric generating facility, which was deactivated in June 2012. The remaining portion of the site consists of a Pepco transmission and distribution service center that remains in operation. In December 2011, the U.S. District Court for the District of Columbia approved a Consent Decree entered into by Pepco and Pepco Energy Services with the DOEE, which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10 to 15-acre portion of the adjacent Anacostia River.

Since 2013, Pepco and Pepco Energy Services (now Generation, pursuant to Exelon's 2016 acquisition of PHI) have been performing RI work and have submitted multiple draft RI reports to the DOEE. In September 2019, Pepco and Generation issued a draft "final" RI report which DOEE approved on February 3, 2020, following a 45-day public comment period and a public meeting. Pepco and Generation are developing a FS to evaluate possible remedial alternatives for submission to DOEE. The Court has established a schedule for completion of the FS, and approval by the DOEE, by September 16, 2021.

DOEE will then prepare a Proposed Plan and issue a Record of Decision identifying any further response actions determined to be necessary, after considering public comment on the Proposed Plan. PHI, Pepco, and Generation have determined that a loss associated with this matter is probable and have accrued an estimated liability, which is included in the table above.

Anacostia River Tidal Reach (Exelon, PHI, and Pepco). Contemporaneous with the Benning Road site RI/FS being performed by Pepco and Generation, DOEE and the National Park Service have been conducting a separate RI/FS focused on the entire tidal reach of the Anacostia River extending from just north of the Maryland-District of Columbia boundary line to the confluence of the Anacostia and Potomac Rivers. The river-wide RI incorporated the results of the river sampling performed by Pepco and Pepco Energy Services as part of the Benning RI/FS, as well as similar sampling efforts conducted by owners of other sites adjacent to this segment of the river and supplemental river sampling conducted by DOEE's contractor. DOEE asked Pepco, along with parties responsible for other sites along the river, to participate in a "Consultative Working Group" to provide input into the process for future remedial actions and to ensure proper coordination with the other river cleanup efforts currently underway, including cleanup of the river segment adjacent to the Benning Road site resulting from the Benning Road site RI/FS. In addition, the District of Columbia Council directed DOEE to form an official advisory committee made up of members of federal, state, and local environmental regulators, community and environmental groups, and various academic and technical experts to provide guidance and support to DOEE as the project progressed. This group, called the Anacostia Leadership Council, has met regularly since it was formed. Pepco has participated in the Consultative Working Group. In April 2018, DOEE released a draft RI report for public review and comment. Pepco submitted written comments to the draft RI and participated in a public hearing.

Pepco has determined that it is probable that costs for remediation will be incurred and recorded a liability in the third quarter 2019 for management's best estimate of its share of those costs based on DOEE's stated position following a series of meetings attended by representatives from the Anacostia Leadership Council and the Consultative Working Group. On December 27, 2019, DOEE released for review and comment by the public a Focused Feasibility Study (FFS) and a Proposed Plan (PP), and 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, however management cannot reasonably estimate a range of loss beyond the amounts recorded, which are included in the table above.

In addition to the activities associated with the remedial process outlined above, CERCLA separately requires federal and state (here including Washington, D.C.) Natural Resource Trustees (federal or state agencies designated by the President or the relevant state, respectively, or Indian tribes) to conduct an assessment of any damages to natural resources within their jurisdiction as a result of the contamination that is being remediated. The Trustees can seek compensation from responsible parties for such damages, including restoration costs. The Natural Resource Damages (NRD) assessment typically takes place following cleanup because cleanups sometimes also effectively restore affected natural resources. During the second quarter of 2018, Pepco became aware that the Trustees are in the beginning stages of this process that often takes many years beyond the remedial decision to complete. Pepco has concluded that a loss associated with the eventual NRD assessment is reasonably possible. Due to the very early stage of the assessment process, Pepco cannot reasonably estimate the range of loss.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims (Exelon and Generation). Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The estimated liabilities are recorded on an undiscounted basis and exclude the estimated legal costs associated with handling these matters, which could be material.

At September 30, 2020 and December 31, 2019, Exelon and Generation had recorded estimated liabilities of approximately $91 million and $83 million, respectively, in total for asbestos-related bodily injury claims. As of September 30, 2020, approximately $27 million of this amount related to 274 open claims presented to Generation, while the remaining $64 million is for estimated future asbestos-related bodily injury claims anticipated to arise through 2055, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether adjustments to the estimated liabilities are necessary.

It is reasonably possible that additional exposure to estimated future asbestos-related bodily injury claims in excess of the amount accrued could have a material, unfavorable impact on Exelon's and Generation's financial statements. However, management cannot reasonably estimate a range of loss beyond the amounts recorded.

City of Everett Tax Increment Financing Agreement (Exelon and Generation). On April 10, 2017, the City of Everett petitioned the Massachusetts Economic Assistance Coordinating Council (EACC) to revoke the 1999 tax increment financing agreement (TIF Agreement) relating to Mystic Units 8 and 9 on the grounds that the total investment in Mystic Units 8 and 9 materially deviates from the investment set forth in the TIF Agreement. On October 31, 2017, a three-member panel of the EACC conducted an administrative hearing on the City's petition. On November 30, 2017, the hearing panel issued a tentative decision denying the City's petition, finding that there was no material misrepresentation that would justify revocation of the TIF Agreement. On December 13, 2017, the tentative decision was adopted by the full EACC. On January 12, 2018, the City filed a complaint in Massachusetts Superior Court requesting, among other things, that the court set aside the EACC's decision, grant the City's request to decertify the Project and the TIF Agreement, and award the City damages for alleged underpaid taxes over the period of the TIF Agreement. On January 8, 2020, the Massachusetts Superior Court affirmed the decision of the EACC denying the City's petition. The City had until March 9, 2020 to appeal the decision and did not. As a result, the decision is final and the case is resolved. It is reasonably possible that property taxes assessed in future periods, including those following the expiration of the TIF Agreement on June 30, 2020, could be material to Generation's financial statements.

Deferred Prosecution Agreement (DPA) and Related Matters (Exelon and ComEd). Exelon and ComEd received a grand jury subpoena in the second quarter of 2019 from the U.S. Attorney's Office for the Northern District of Illinois (USAO) requiring production of information concerning their lobbying activities in the State of Illinois. On October 4, 2019, Exelon and ComEd received a second grand jury subpoena from the USAO requiring production of records of any communications with certain individuals and entities. On October 22, 2019, the SEC notified Exelon and ComEd that it had also opened an investigation into their lobbying activities. On July 17, 2020, ComEd entered into a DPA with the USAO to resolve the USAO investigation. Under the DPA, the USAO filed a single charge alleging that ComEd improperly gave and offered to give jobs, vendor subcontracts, and payments associated with those jobs and subcontracts for the benefit of the Speaker of the Illinois House of Representatives and the Speaker's associates, with the intent to influence the Speaker's action regarding legislation affecting ComEd's interests. The DPA provides that the USAO will defer any prosecution of such charge and any other criminal or civil case against ComEd in connection with the matters identified therein for a three-year period subject to certain obligations of ComEd, including payment to the U.S. Treasury of $200 million, with $100 million payable within thirty days of the filing of the DPA with the United States District Court for the Northern District of Illinois and an additional $100 million within ninety days of such filing date. The payments were recorded within Operating and maintenance expense in Exelon's and ComEd's Consolidated Statements of Operations and Comprehensive Income in the second quarter of 2020. The payments will not be recovered in rates or charged to customers and ComEd will not seek or accept reimbursement or indemnification from any source other than Exelon. Exelon made equity contributions to ComEd of $100 million in August 2020 and $100 million in October 2020. On August 13, 2020, a motion was filed in the U.S. District Court for the Northern District of Illinois by and on behalf of ComEd customers seeking to enjoin ComEd from paying these funds to the U.S. Treasury and requiring the U.S. government to establish a victims' restitution fund from which the $200 million would be disbursed to ComEd customers. The U.S. government and ComEd filed briefs in opposition to this motion. The motion remains pending, and at the U.S. government's direction, the $200 million payment will not be transferred to the U.S. Treasury until the court rules on the motion. $100 million was recorded as Restricted cash and cash equivalents on Exelon's and ComEd's Consolidated Balance Sheets as of September 30, 2020 and $100 million was recorded as restricted cash in October 2020.

Exelon was not made a party to the DPA, and therefore the investigation by the USAO into Exelon's activities ends with no charges being brought against Exelon.

The SEC's investigation remains ongoing and Exelon and ComEd have cooperated fully and intend to continue to cooperate fully with the SEC. Exelon and ComEd cannot predict the outcome of the SEC investigation. No loss contingency has been reflected in Exelon's and ComEd's consolidated financial statements with respect to the SEC investigation, as this contingency is neither probable nor reasonably estimable at this time.

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

- A putative class action lawsuit against Exelon and certain officers of Exelon and ComEd was filed in federal court in December 2019 alleging misrepresentations and omissions in Exelon's SEC filings related to ComEd's lobbying activities and the related investigations. The complaint was amended on September 16, 2020, to dismiss two of the original defendants and add other defendants, including ComEd.
- A derivative shareholder lawsuit was filed against Exelon, its directors and certain officers of Exelon and ComEd in April 2020 alleging, among other things, breaches of fiduciary duties also purporting to relate to matters that are the subject of the subpoenas and the SEC investigation. The plaintiff voluntarily dismissed this derivative action without prejudice to refile on July 28, 2020.

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

- Three putative class action lawsuits against ComEd and Exelon were filed in Illinois state court in the third quarter of 2020 seeking restitution and compensatory damages on behalf of ComEd customers. These three state cases were consolidated into a single action in October of 2020. In addition, on November 2, 2020, the Citizens Utility Board (CUB) filed a motion to intervene in the state cases pursuant to an Illinois statute allowing the CUB to intervene as a party or otherwise participate on behalf of utility consumers in any proceeding which affects the interest of utility consumers. The CUB has requested that the court stay the state cases pending the resolution of the federal cases, described below.

- Four putative class action lawsuits against ComEd and Exelon were filed in federal court in the third quarter of 2020 alleging, among other things, civil violations of federal racketeering laws. In addition, the CUB filed a motion to intervene in these cases on October 22, 2020 and filed a proposed complaint against ComEd in conjunction with that motion alleging Racketeer Influenced and Corrupt Organization Act (RICO) and other causes of action on October 29, 2020.

- Two shareholders sent letters to the Exelon Board of Directors in the third quarter of 2020 demanding, among other things, that the Exelon Board of Directors investigate and address alleged breaches of fiduciary duties and other alleged violations by Exelon and ComEd officers and directors related to the conduct described in the DPA.

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

General (All Registrants). The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

15. Changes in Accumulated Other Comprehensive Income (Exelon)

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

Three Months Ended September 30, 2020	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items [(a)]	Foreign Currency Items	Total
Beginning balance	$ (3)	$ (3,096)	$ (33)	$ (3,132)
OCI before reclassifications	(1)	(13)	3	(11)
Amounts reclassified from AOCI	—	39	—	39
Net current-period OCI	(1)	26	3	28
Ending balance	$ (4)	$ (3,070)	$ (30)	$ (3,104)

Three Months Ended September 30, 2019	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items [(a)]	Foreign Currency Items	AOCI of Investments in Unconsolidated Affiliates [(b)]	Total
Beginning balance	$ (2)	$ (2,957)	$ (29)	$ (2)	$ (2,990)
OCI before reclassifications	—	6	(2)	—	4
Amounts reclassified from AOCI	—	21	—	2	23
Net current-period OCI	—	27	(2)	2	27
Ending balance	$ (2)	$ (2,930)	$ (31)	$ —	$ (2,963)

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

Nine Months Ended September 30, 2020	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items [(a)]	Foreign Currency Items	Total
Beginning balance	$ (2)	$ (3,165)	$ (27)	$ (3,194)
OCI before reclassifications	(2)	(17)	(3)	(22)
Amounts reclassified from AOCI	—	112	—	112
Net current-period OCI	(2)	95	(3)	90
Ending balance	$ (4)	$ (3,070)	$ (30)	$ (3,104)

Nine Months Ended September 30, 2019	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items [(a)]	Foreign Currency Items	AOCI of Investments in Unconsolidated Affiliates [(b)]	Total
Beginning balance	$ (2)	$ (2,960)	$ (33)	$ —	$ (2,995)
OCI before reclassifications	—	(32)	2	(2)	(32)
Amounts reclassified from AOCI	—	62	—	2	64
Net current-period OCI	—	30	2	—	32
Ending balance	$ (2)	$ (2,930)	$ (31)	$ —	$ (2,963)

____
(a) AOCI amounts are included in the computation of net periodic pension and OPEB cost. See Note 10 — Retirement Benefits for additional information. See Exelon's Statements of Operations and Comprehensive Income for individual components of AOCI.
(b) All amounts are net of noncontrolling interests.

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

	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	$ 4	$ 6	$ 12	$ 18
Actuarial loss reclassified to periodic benefit cost	(16)	(13)	(50)	(39)
Pension and non-pension postretirement benefit plans valuation adjustment	3	—	6	14

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

At September 30, 2020 and December 31, 2019, Exelon, Generation, PHI, and ACE collectively consolidated several VIEs or VIE groups for which the applicable Registrant was the primary beneficiary (see *Consolidated VIEs* below) and had significant interests in several other VIEs for which the applicable Registrant does not have the power to direct the entities' activities and, accordingly, was not the primary beneficiary (see *Unconsolidated VIEs* below). Consolidated and unconsolidated VIEs are aggregated to the extent that the entities have similar risk profiles.

Consolidated VIEs

The table below shows the carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the consolidated financial statements of Exelon, Generation, PHI, and ACE as of September 30, 2020 and December 31, 2019. The assets, except as noted in the footnotes to the table below, can only be used to settle obligations of the VIEs. The liabilities, except as noted in the footnote to the table below, are such that creditors, or beneficiaries, do not have recourse to the general credit of Exelon, Generation, PHI, and ACE.

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

	September 30, 2020				December 31, 2019			
	Exelon	Generation	PHI [(a)]	ACE	Exelon	Generation	PHI [(a)]	ACE
Cash and cash equivalents	$ 148	$ 148	$ —	$ —	$ 163	$ 163	$ —	$ —
Restricted cash and cash equivalents	52	48	4	4	88	85	3	3
Accounts receivable								
Customer	151	151	—	—	151	151	—	—
Other	39	39	—	—	39	39	—	—
Unamortized energy contract assets	22	22	—	—	23	23	—	—
Inventories, net								
Materials and supplies	241	241	—	—	227	227	—	—
Other current assets	781	776	5	—	32	31	1	—
Total current assets	1,434	1,425	9	4	723	719	4	3
Property, plant, and equipment, net	5,865	5,865	—	—	6,022	6,022	—	—
Nuclear decommissioning trust funds	2,785	2,785	—	—	2,741	2,741	—	—
Unamortized energy contract assets	253	253	—	—	250	250	—	—
Other noncurrent assets	49	38	11	10	89	73	16	14
Total noncurrent assets	8,952	8,941	11	10	9,102	9,086	16	14
Total assets [(b)]	$ 10,386	$ 10,366	$ 20	$ 14	$ 9,825	$ 9,805	$ 20	$ 17
Long-term debt due within one year	$ 134	$ 109	$ 25	$ 20	$ 544	$ 523	$ 21	$ 20
Accounts payable	81	81	—	—	106	106	—	—
Accrued expenses	63	63	—	—	70	70	—	—
Unamortized energy contract liabilities	5	5	—	—	8	8	—	—
Other current liabilities	26	26	—	—	3	3	—	—
Total current liabilities	309	284	25	20	731	710	21	20
Long-term debt	913	906	7	6	527	504	23	21
Asset retirement obligations	2,210	2,210	—	—	2,128	2,128	—	—
Unamortized energy contract liabilities	1	1	—	—	1	1	—	—
Other noncurrent liabilities	106	106	—	—	89	89	—	—
Total noncurrent liabilities	3,230	3,223	7	6	2,745	2,722	23	21
Total liabilities [(c)]	$ 3,539	$ 3,507	$ 32	$ 26	$ 3,476	$ 3,432	$ 44	$ 41

(a) Includes certain purchase accounting adjustments not pushed down to the ACE standalone entity.
(b) Exelon's and Generation's balances include unrestricted assets for current unamortized energy contract assets of $22 million and $23 million, Property, plant, and equipment of $1 million and $20 million, non-current unamortized energy contract assets of $253 million and $250 million, and other unrestricted assets of $8 million and $0 million as of September 30, 2020 and December 31, 2019, respectively
(c) Exelon's and Generation's balances include liabilities with recourse of $8 million and $3 million as of September 30, 2020 and December 31, 2019, respectively.

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

As of September 30, 2020 and December 31, 2019, Exelon's and Generation's consolidated VIEs consist of:

Consolidated VIE or VIE groups:	Reason entity is a VIE:	Reason Generation is primary beneficiary:
CENG - A joint venture between Generation and EDF. Generation has a 50.01% equity ownership in CENG. See additional discussion below.	Disproportionate relationship between equity interest and operational control as a result of NOSA described further below.	Generation conducts the operational activities.
EGRP - A collection of wind and solar project entities. Generation has a 51% equity ownership in EGRP. See additional discussion below.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	Generation conducts the operational activities.
Bluestem Wind Energy Holdings, LLC - A Tax Equity structure which is consolidated by EGRP. Generation is a minority interest holder.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	Generation conducts the operational activities.
Antelope Valley - A solar generating facility, which is 100% owned by Generation. Antelope Valley sells all of its output to PG&E through a PPA.	The PPA contract absorbs variability through a performance guarantee.	Generation conducts all activities.
Equity investment in distributed energy company - Generation has a 31% equity ownership. This distributed energy company has an interest in an unconsolidated VIE (see Unconsolidated VIEs disclosure below). Generation fully impaired this investment in the third quarter of 2019. See Note 11—Asset Impairments of the Exelon 2019 Form 10-K for additional information.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	Generation conducts the operational activities.
NER - A bankruptcy remote, special purpose entity which is 100% owned by Generation, which purchases certain of Generation's customer accounts receivable arising from the sale of retail electricity. NER's assets will be available first and foremost to satisfy the claims of the creditors of NER. See Note 5 - Accounts Receivable for additional information on the sale of receivables.	Equity capitalization is insufficient to support its operations.	Generation conducts all activities.

CENG - On April 1, 2014, Generation, CENG, and subsidiaries of CENG executed the NOSA pursuant to which Generation conducts all activities associated with the operations of the CENG fleet and provides corporate and administrative services to CENG and the CENG fleet for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF.

EDF has the option to sell its 49.99% equity interest in CENG to Generation exercisable beginning on January 1, 2016 and thereafter until June 30, 2022. On November 20, 2019, Generation received notice of EDF's intention to exercise the put option to sell its interest in CENG to Generation and the put automatically exercised on January 19, 2020 at the end of the sixty-day advance notice period.

At this time, Generation cannot reasonably predict the ultimate purchase price that will be paid to EDF for its interest in CENG. The transaction will require approval by the NYPSC and the FERC. The FERC approval was obtained on July 30, 2020. From the date the put was exercised, the process and regulatory approvals could take one to two years to complete.

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

Exelon and Generation, where indicated, provide the following support to CENG:

- Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this Indemnity Agreement. See Note 18 — Commitments and Contingencies of the Exelon 2019 Form 10-K for more details,

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

- Generation and EDF share in the $688 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance, and
- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG's cash pooling agreement with its subsidiaries.

EGRP - EGRP is a collection of wind and solar project entities and some of these project entities are VIEs that are consolidated by EGRP. Generation owns a number of limited liability companies that build, own, and operate solar and wind power facilities some of which are owned by EGRP. While Generation or EGRP owns 100% of the solar entities and 100% of the majority of the wind entities, it has been determined that certain of the solar and wind entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of these solar and wind entities that qualify as VIEs because Generation controls the design, construction, and operation of the facilities. Generation provides operating and capital funding to the solar and wind entities for ongoing construction, operations and maintenance and there is limited recourse related to Generation related to certain solar and wind entities.

In 2017, Generation's interests in EGRP were contributed to and are pledged for the ExGen Renewables IV non-recourse debt project financing structure. Refer to Note 12— Debt and Credit Agreements for additional information on ExGen Renewables IV.

As of September 30, 2020 and December 31, 2019, Exelon's, PHI's and ACE's consolidated VIE consists of:

Consolidated VIEs:	Reason entity is a VIE:	Reason ACE is the primary beneficiary:
ACE Funding - A special purpose entity formed by ACE for the purpose of securitizing authorized portions of ACE's recoverable stranded costs through the issuance and sale of Transition Bonds. Proceeds from the sale of each series of Transition Bonds by ATF were transferred to ACE in exchange for the transfer by ACE to ATF of the right to collect a non-bypassable Transition Bond Charge from ACE customers pursuant to bondable stranded costs rate orders issued by the NJBPU in an amount sufficient to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees.	ACE's equity investment is a variable interest as, by design, it absorbs any initial variability of ATF. The bondholders also have a variable interest for the investment made to purchase the Transition Bonds.	ACE controls the servicing activities.

Unconsolidated VIEs

Exelon's and Generation's variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected in Exelon's and Generation's Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements.

As of September 30, 2020 and December 31, 2019, Exelon and Generation had significant unconsolidated variable interests in several VIEs for which Exelon or Generation, as applicable, was not the primary beneficiary. These interests include certain equity method investments and certain commercial agreements.

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

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

	September 30, 2020			December 31, 2019		
	Commercial Agreement VIEs	Equity Investment VIEs	Total	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 736	$ 409	$ 1,145	$ 636	$ 443	$ 1,079
Total liabilities[(a)]	216	225	441	33	227	260
Exelon's ownership interest in VIE[(a)]	—	163	163	—	191	191
Other ownership interests in VIE[(a)]	520	21	541	604	25	629

____
(a) These items represent amounts on the unconsolidated VIE balance sheets, not in Exelon's or Generation's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs. Exelon and Generation do not have any exposure to loss as they do not have a carrying amount in the equity investment VIEs as of September 30, 2020 and December 31, 2019.

As of September 30, 2020 and December 31, 2019, Exelon's and Generation's unconsolidated VIEs consist of:

Unconsolidated VIE groups:	Reason entity is a VIE:	Reason Generation is not the primary beneficiary:
Equity investments in distributed energy companies - 1) Generation has a 90% equity ownership in a distributed energy company. 2) Generation, via a consolidated VIE, has a 90% equity ownership in another distributed energy company (See Consolidated VIEs disclosure above). Generation fully impaired this investment in the third quarter of 2019. See Note 11—Asset Impairments of the Exelon 2019 Form 10-K for additional information.	Similar structures to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	Generation does not conduct the operational activities.
Energy Purchase and Sale agreements - Generation has several energy purchase and sale agreements with generating facilities.	PPA contracts that absorb variability through fixed pricing.	Generation does not conduct the operational activities.

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

17. Supplemental Financial Information (All Registrants)

Supplemental Statement of Operations Information

The following tables provide additional information about material items recorded in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

	Operating revenues			
	Exelon	Generation	PHI	DPL
Three Months Ended September 30, 2020				
Operating lease income	$ 30	$ 28	$ 1	$ 1
Variable lease income	76	76	—	—
Three Months Ended September 30, 2019				
Operating lease income	$ 30	$ 29	$ 1	$ 1
Variable lease income	80	80	—	—
Nine Months Ended September 30, 2020				
Operating lease income	$ 48	$ 43	$ 3	$ 3
Variable lease income	225	224	1	1
Nine Months Ended September 30, 2019				
Operating lease income	$ 48	$ 44	$ 3	$ 3
Variable lease income	209	206	3	3

	Taxes other than income taxes								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Three Months Ended September 30, 2020									
Utility taxes(a)	$ 237	$ 26	$ 66	$ 41	$ 21	$ 83	$ 77	$ 5	$ 1
Property	152	66	7	4	42	32	21	10	1
Payroll	59	29	7	4	4	6	2	1	1
Three Months Ended September 30, 2019									
Utility taxes(a)	$ 241	$ 29	$ 66	$ 38	$ 21	$ 86	$ 81	$ 5	$ —
Property	148	66	7	5	39	31	21	9	—
Payroll	57	28	7	3	4	6	2	1	1
Nine Months Ended September 30, 2020									
Utility taxes(a)	$ 651	$ 75	$ 181	$ 102	$ 65	$ 228	$ 210	$ 16	$ 2
Property	449	199	23	12	121	94	63	29	2
Payroll	183	88	21	12	13	21	6	4	3
Nine Months Ended September 30, 2019									
Utility taxes(a)	$ 672	$ 87	$ 183	$ 102	$ 68	$ 231	$ 217	$ 14	$ —
Property	444	205	22	12	114	91	64	25	2
Payroll	185	92	21	11	13	20	5	3	2

(a) Generation's utility tax represents gross receipts tax related to its retail operations, and the Utility Registrants' utility taxes represents municipal and state utility taxes and gross receipts taxes related to their operating revenues. The offsetting collection of utility taxes from customers is recorded in revenues in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

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

	Other, Net								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Three Months Ended September 30, 2020									
Decommissioning-related activities:									
Net realized income on NDT funds[a]									
Regulatory agreement units	$ 50	$ 50	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-regulatory agreement units	23	23	—	—	—	—	—	—	—
Net unrealized gains on NDT funds									
Regulatory agreement units	398	398	—	—	—	—	—	—	—
Non-regulatory agreement units	254	254	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities[b]	(359)	(359)	—	—	—	—	—	—	—
Decommissioning-related activities	366	366	—	—	—	—	—	—	—
AFUDC — Equity	27	—	7	5	6	9	7	1	1
Non-service net periodic benefit cost	15	—	—	—	—	—	—	—	—
Three Months Ended September 30, 2019									
Decommissioning-related activities:									
Net realized income on NDT funds[a]									
Regulatory agreement units	$ 67	$ 67	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-regulatory agreement units	33	33	—	—	—	—	—	—	—
Net unrealized gains on NDT funds									
Regulatory agreement units	89	89	—	—	—	—	—	—	—
Non-regulatory agreement units	55	55	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities[b]	(125)	(125)	—	—	—	—	—	—	—
Decommissioning-related activities	119	119	—	—	—	—	—	—	—
AFUDC — Equity	22	—	4	3	6	9	7	1	1
Non-service net periodic benefit cost	(2)	—	—	—	—	—	—	—	—

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

Table of Contents

			Other, net						
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Nine Months Ended September 30, 2020									
Decommissioning-related activities:									
Net realized income on NDT funds[a]									
Regulatory agreement units	$ 127	$ 127	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-regulatory agreement units	127	127	—	—	—	—	—	—	—
Net unrealized gains on NDT funds									
Regulatory agreement units	111	111	—	—	—	—	—	—	—
Non-regulatory agreement units	1	1	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities[b]	(192)	(192)	—	—	—	—	—	—	—
Decommissioning-related activities	174	174	—	—	—	—	—	—	—
AFUDC — Equity	76	—	22	12	16	26	20	3	3
Non-service net periodic benefit cost	38	—	—	—	—	—	—	—	—
Nine Months Ended September 30, 2019									
Decommissioning-related activities:									
Net realized income on NDT funds[a]									
Regulatory agreement units	$ 197	$ 197	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-regulatory agreement units	316	316	—	—	—	—	—	—	—
Net unrealized gains on NDT funds									
Regulatory agreement units	565	565	—	—	—	—	—	—	—
Non-regulatory agreement units	236	236	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities[b]	(611)	(611)	—	—	—	—	—	—	—
Decommissioning-related activities	703	703	—	—	—	—	—	—	—
AFUDC — Equity	64	—	13	9	16	26	18	3	4
Non-service net periodic benefit cost	8	—	—	—	—	—	—	—	—

____
(a) Realized income includes interest, dividends and realized gains and losses on sales of NDT fund investments.
(b) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units, including the elimination of income taxes related to all NDT fund activity for those units. See Note 9 — Asset Retirement Obligations of the Exelon 2019 Form 10-K for additional information regarding the accounting for nuclear decommissioning.

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

Supplemental Cash Flow Information

The following tables provide additional information about material items recorded in the Registrants' Consolidated Statements of Cash Flows.

	Depreciation, amortization and accretion								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Nine Months Ended September 30, 2020									
Property, plant, and equipment[(a)]	$ 2,831	$ 1,121	$ 689	$ 238	$ 293	$ 436	$ 191	$ 116	$ 104
Amortization of regulatory assets[(a)]	434	—	152	21	112	149	91	27	30
Amortization of intangible assets, net[(a)]	47	40	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities[(b)]	24	22	—	—	—	—	—	—	—
Nuclear fuel[(c)]	708	708	—	—	—	—	—	—	—
ARO accretion[(d)]	375	375	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$ 4,419	$ 2,266	$ 841	$ 259	$ 405	$ 585	$ 282	$ 143	$ 134
Nine Months Ended September 30, 2019									
Property, plant, and equipment[(a)]	$ 2,803	$ 1,184	$ 661	$ 225	$ 263	$ 405	$ 178	$ 109	$ 89
Amortization of regulatory assets[(a)]	390	—	106	22	105	157	103	29	25
Amortization of intangible assets, net[(a)]	44	37	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities[(b)]	14	14	—	—	—	—	—	—	—
Nuclear fuel[(c)]	771	771	—	—	—	—	—	—	—
ARO accretion[(d)]	371	371	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$ 4,393	$ 2,377	$ 767	$ 247	$ 368	$ 562	$ 281	$ 138	$ 114

____

(a) Included in Depreciation and amortization in the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(b) Included in Operating revenues or Purchased power and fuel expense in the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(c) Included in Purchased power and fuel expense in the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(d) Included in Operating and maintenance expense in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

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

	Other non-cash operating activities								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Nine Months Ended September 30, 2020									
Pension and non-pension postretirement benefit costs	$ 310	$ 89	$ 85	$ 4	$ 46	$ 52	$ 11	$ 6	$ 10
Provision for uncollectible accounts	130	16	23	38	12	41	24	15	2
Other decommissioning-related activity[(a)]	(301)	(301)	—	—	—	—	—	—	—
Energy-related options[(b)]	79	79	—	—	—	—	—	—	—
True-up adjustments to decoupling mechanisms and formula rates[(c)]	66	—	51	(10)	10	15	(20)	15	20
Severance Costs	96	88	1	—	—	—	—	—	—
Provision for excess and obsolete inventory	119	118	1	1	—	(1)	—	(1)	—
Long-term incentive plan	(8)	—	—	—	—	—	—	—	—
Amortization of operating ROU asset	185	135	1	—	23	21	5	6	2
Deferred Prosecution Agreement payments[(d)]	200	—	200	—	—	—	—	—	—
Nine Months Ended September 30, 2019									
Pension and non-pension postretirement benefit costs	$ 324	$ 98	$ 70	$ 9	$ 45	$ 71	$ 19	$ 11	$ 12
Provision for uncollectible accounts	89	20	26	22	5	16	7	2	6
Other decommissioning-related activity[(a)]	(400)	(400)	—	—	—	—	—	—	—
Energy-related options[(b)]	21	21	—	—	—	—	—	—	—
True-up adjustments to decoupling mechanisms and formula rates[(e)]	72	—	80	—	—	(8)	(9)	1	—
Long-term incentive plan	33	—	—	—	—	—	—	—	—
Amortization of operating ROU asset	193	138	2	—	23	26	6	7	4
Change in environmental liabilities	23	—	—	—	—	23	23	—	—

____

(a) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income, and income taxes related to all NDT fund activity for these units. See Note 9 — Asset Retirement Obligations of the Exelon 2019 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) For ComEd, reflects the true-up adjustments in regulatory assets and liabilities associated with its distribution, energy efficiency, distributed generation, and transmission formula rates. For BGE, Pepco, and DPL, reflects the change in regulatory assets and liabilities associated with their decoupling mechanisms and transmission formula rates. For PECO and ACE, reflects the change in regulatory assets and liabilities associated with their transmission formula rates. See Note 2 — Regulatory Matters for additional information.
(d) See Note 14 — Commitments and Contingencies for additional information related to the Deferred Prosecution Agreement.
(e) 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 2 — Regulatory Matters for additional information.

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

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

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
September 30, 2020									
Cash and cash equivalents	$ 1,858	$ 623	$ 76	$ 242	$ 326	$ 196	$ 125	$ 26	$ 13
Restricted cash	485	100	305	7	1	38	33	—	4
Restricted cash included in other long-term assets	137	—	127	—	—	10	—	—	10
Total cash, cash equivalents and restricted cash	$ 2,480	$ 723	$ 508	$ 249	$ 327	$ 244	$ 158	$ 26	$ 27
December 31, 2019									
Cash and cash equivalents	$ 587	$ 303	$ 90	$ 21	$ 24	$ 131	$ 30	$ 13	$ 12
Restricted cash	358	146	150	6	1	36	33	—	2
Restricted cash included in other long-term assets	177	—	163	—	—	14	—	—	14
Total cash, cash equivalents and restricted cash	$ 1,122	$ 449	$ 403	$ 27	$ 25	$ 181	$ 63	$ 13	$ 28
September 30, 2019									
Cash and cash equivalents	$ 1,683	$ 1,019	$ 76	$ 224	$ 130	$ 99	$ 18	$ 11	$ 13
Restricted cash	309	126	124	6	1	38	34	—	3
Restricted cash included in other long-term assets	186	—	171	—	—	15	—	—	15
Total cash, cash equivalents and restricted cash	$ 2,178	$ 1,145	$ 371	$ 230	$ 131	$ 152	$ 52	$ 11	$ 31
December 31, 2018									
Cash and cash equivalents	$ 1,349	$ 750	$ 135	$ 130	$ 7	$ 124	$ 16	$ 23	$ 7
Restricted cash	247	153	29	5	6	43	37	1	4
Restricted cash included in other long-term assets	185	—	166	—	—	19	—	—	19
Total cash, cash equivalents and restricted cash	$ 1,781	$ 903	$ 330	$ 135	$ 13	$ 186	$ 53	$ 24	$ 30

For additional information on restricted cash see Note 1 — Significant Accounting Policies of the Exelon 2019 Form 10-K.

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

Supplemental Balance Sheet Information

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

	Accrued expenses								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
September 30, 2020									
Compensation-related accruals[(a)]	$ 898	$ 352	$ 147	$ 60	$ 72	$ 95	$ 31	$ 16	$ 14
Taxes accrued	403	183	55	25	63	84	65	10	3
Interest accrued	440	79	64	36	40	80	38	21	21
December 31, 2019									
Compensation-related accruals[(a)]	$ 1,052	$ 422	$ 171	$ 58	$ 78	$ 101	$ 28	$ 19	$ 15
Taxes accrued	414	222	83	3	26	117	90	14	8
Interest accrued	337	65	110	37	46	49	23	8	12

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

18. Related Party Transactions (All Registrants)

Operating revenues from affiliates

Generation

The following table presents Generation's Operating revenues from affiliates, which are primarily recorded as Purchased power from affiliates and an immaterial amount recorded as Operating and maintenance expense from affiliates at the Utility Registrants:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Operating revenues from affiliates:				
ComEd[(a)(b)]	$ 71	$ 83	$ 241	$ 266
PECO[(c)]	68	43	146	123
BGE[(d)]	84	65	252	199
PHI	105	83	288	254
Pepco[(e)]	80	66	219	188
DPL[(f)]	21	14	60	50
ACE[(g)]	4	3	9	16
Other	3	1	5	2
Total operating revenues from affiliates (Generation)	$ 331	$ 275	$ 932	$ 844

(a) Generation has an ICC-approved RFP contract with ComEd to provide a portion of ComEd's electricity supply requirements. Generation also sells RECs and ZECs to ComEd.
(b) For the three and nine months ended September 30, 2020 , respectively, ComEd's Purchased power from Generation of $71 million and $252 million is recorded as Operating revenues from ComEd of $71 million and $241 million and as Purchased power and fuel from ComEd of less than $1 million and $11 million at Generation. For the three and nine months ended September 30, 2019 , respectively, ComEd's Purchased power from Generation of $83 million and $270 million is recorded as Operating revenues from ComEd of $83 million and $266 million and as Purchased power and fuel from ComEd of less than $1 million and $4 million at Generation.
(c) Generation provides electric supply to PECO under contracts executed through PECO's competitive procurement process. In addition, Generation has a ten-year agreement with PECO to sell solar AECs.

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

(d) Generation provides a portion of BGE's energy requirements under its MDPSC-approved market-based SOS and gas commodity programs.
(e) Generation provides electric supply to Pepco under contracts executed through Pepco's competitive procurement process approved by the MDPSC and DCPSC.
(f) Generation provides a portion of DPL's energy requirements under its MDPSC and DPSC approved market based SOS and gas commodity programs.
(g) Generation provides electric supply to ACE under contracts executed through ACE's competitive procurement process.

PHI

PHI's Operating revenues from affiliates are primarily with BSC for services that PHISCO provides to BSC.

Operating and maintenance expense from affiliates

The Registrants receive a variety of corporate support services from BSC. Pepco, DPL, and ACE also receive corporate support services from PHISCO. See Note 1 - Significant Accounting Policies for additional information regarding BSC and PHISCO.

The following table presents the service company costs allocated to the Registrants:

	Operating and maintenance from affiliates				Capitalized costs			
	Three Months Ended September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019	2020	2019	2020	2019
Exelon								
BSC					$ 148	$ 125	$ 390	$ 357
PHISCO					15	16	45	57
Generation								
BSC	$ 133	$ 138	$ 406	$ 434	13	18	37	44
ComEd								
BSC	65	72	204	195	49	37	133	98
PECO								
BSC	34	36	107	110	20	22	53	68
BGE								
BSC	38	38	120	116	30	30	88	89
PHI								
BSC	36	35	107	102	36	18	79	58
PHISCO	—	—	—	—	15	16	45	57
Pepco								
BSC	20	21	61	64	14	8	29	25
PHISCO	28	29	90	92	7	8	20	26
DPL								
BSC	13	13	38	39	12	5	26	16
PHISCO	24	24	73	74	4	4	13	16
ACE								
BSC	11	10	32	31	10	4	22	13
PHISCO	21	22	65	67	4	4	12	15

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

Current Receivables from/Payables to affiliates

The following tables present current receivables from affiliates and current payables to affiliates:

September 30, 2020

	Receivables from affiliates:								
Payables to affiliates:	**Generation**	**ComEd**	**PECO**	**BGE**	**ACE**	**BSC**	**PHISCO**	**Other**	**Total**
Generation		$ 19	$ —	$ —	$ —	$ 69	$ —	$ 25	$ 113
ComEd	$ 56 [(a)]		—	—	—	49	—	5	110
PECO	17	—		—	—	24	—	6	47
BGE	8	—	—		—	29	—	2	39
PHI	—	—	—	—	—	3	—	10	13
Pepco	13	—	—	—	—	16	12	2	43
DPL	2	—	—	—	—	11	9	1	23
ACE	4	—	—	—		10	10	—	24
Other	9	1	—	—	1	—	—		11
Total	$ 109	$ 20	$ —	$ —	$ 1	$ 211	$ 31	$ 51	$ 423

December 31, 2019

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

____

(a) As of September 30, 2020 and December 31, 2019, Generation had a contract liability with ComEd for $28 million and $37 million, respectively, that was included in Other current liabilities on Generation's Consolidated Balance Sheets. At September 30, 2020 and December 31, 2019, ComEd had a Current Payable to Generation of $28 million and $41 million, respectively, on its Consolidated Balance Sheets, which consisted of Generation's Current Receivable from ComEd, partially offset by Generation's contract liability with ComEd.

Borrowings from Exelon/PHI intercompany money pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing both Exelon and PHI operate an intercompany money pool. Generation, ComEd, PECO, and PHI Corporate participate in the Exelon money pool. Pepco, DPL, and ACE participate in the PHI intercompany money pool.

Noncurrent Receivables from/Payables to affiliates

Generation has long-term payables to ComEd and PECO as a result of the nuclear decommissioning contractual construct whereby, to the extent NDT funds are greater than the underlying ARO at the end of decommissioning, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 9 — Asset Retirement Obligations of the Exelon 2019 Form 10-K for additional information.

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

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

Table of Contents

	September 30, 2020	December 31, 2019
ComEd	$ 2,445	$ 2,622
PECO	443	480
Other	—	1
Total:	$ 2,888	$ 3,103

Long-term debt to financing trusts

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

	September 30, 2020			December 31, 2019		
	Exelon	ComEd	PECO	Exelon	ComEd	PECO
ComEd Financing III	$ 206	$ 205	$ —	$ 206	$ 205	$ —
PECO Trust III	81	—	81	81	—	81
PECO Trust IV	103	—	103	103	—	103
Total	$ 390	$ 205	$ 184	$ 390	$ 205	$ 184

Long-term debt to affiliates

In connection with the debt obligations assumed by Exelon as part of the Constellation merger, Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable included in Long-term debt to affiliates in Generation’s Consolidated Balance Sheets and intercompany notes receivable at Exelon Corporate.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

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

Exelon

Executive Overview

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

Exelon has eleven reportable segments consisting of Generation's five reportable segments (Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions), ComEd, PECO, BGE, Pepco, DPL, and ACE. See Note 1 — Significant Accounting Policies and Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's principal subsidiaries and reportable segments.

Exelon's consolidated financial information includes the results of its eight separate operating subsidiary registrants, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

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

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

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

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

As a result of COVID-19, Generation temporarily suspended interruption of service for all retail residential customers for non-payment and temporarily ceased new late payment fees for all retail customers from March to May of 2020. Starting in March of 2020, the Utility Registrants also temporarily suspended customer disconnections for non-payment and temporarily ceased new late payment fees for all customers and restored service to customers upon request who were disconnected in the last twelve months. See Note 2 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on such measures at the Utility Registrants. At Generation, such measures resulted in an increase in credit loss expense. ComEd and ACE recorded regulatory assets for the incremental credit loss expense based on existing mechanisms. BGE, PECO, Pepco, and DPL recorded regulatory assets in the third quarter of 2020 for substantially all the incremental credit loss expense, including the expense recorded in the second quarter of 2020. See Note 2 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Generation and the Utility Registrants have also incurred direct costs related to COVID-19 consisting primarily of costs to acquire personal protective equipment, costs for cleaning supplies and services, and costs to hire healthcare professionals to monitor the health of their employees. At Generation and PECO, such costs are recorded as Operating and maintenance expense and are excluded from Adjusted (non-GAAP) Operating Earnings. At ComEd, BGE, Pepco, DPL, and ACE, such costs are primarily recorded as regulatory assets. See Note 2 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information. The regulatory assets recorded at BGE, Pepco, DPL, and ACE in the third quarter of 2020 include expense recorded in the second quarter of 2020.

The estimated impact to Generation's Net income is approximately $45 million and $140 million for the three and nine months ended September 30, 2020, respectively. The estimated impact to the Utility Registrants' Net income is approximately $15 million and $65 million for the three and nine months ended September 30, 2020, respectively.

In the fourth quarter of 2020, Generation estimates a decrease in Net income due to net reduction in load of $15 million to $25 million. Generation load forecasts are highly dependent on many factors including, but not limited to, the duration of remaining restrictions and the speed and strength of the economic recovery.

To offset the unfavorable impacts from COVID-19, the Registrants identified and are pursuing approximately $250 million in cost savings across Generation and the Utility Registrants. The cost savings for the year are expected to be higher than originally anticipated.

The Registrants rely on the capital markets for publicly offered debt as well as the commercial paper markets to meet their financial commitments and short-term liquidity needs. As a result of the disruptions in the commercial paper markets in March of 2020, Generation borrowed $1.5 billion on its revolving credit facility to refinance commercial paper, which Generation repaid on April 3, 2020. Generation also entered into two short-term loan agreements in March of 2020 for an aggregate of $500 million. On April 8, 2020, Generation received approximately $500 million in cash after entering into an accounts receivable financing arrangement. On April 24, 2020, Exelon Corporate entered into a credit agreement establishing a $550 million 364-day revolving credit facility to be used as an additional source of short-term liquidity. In addition, to date in 2020, the Registrants have issued long-term debt of $5.3 billion and have now completed their planned long-term debt issuances for the 2020 year. See Liquidity and Capital Resources, Note 12 - Debt and Credit Agreements, and Note 5 - Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants assessed long-lived assets, goodwill, and investments for recoverability and there were no material impairment charges recorded to date in 2020 as a result of COVID-19. See Note 8 — Asset Impairments for additional information related to other impairment assessments in the third quarter of 2020. Certain assumptions are highly sensitive to changes. Changes in significant assumptions could potentially result in future impairments, which could be material.

This is an evolving situation that could lead to extended disruption of economic activity in our markets. The Registrants will continue to monitor developments affecting our workforce, our customers, and our suppliers and we will take additional precautions that we determine are necessary in order to mitigate the impacts. The extent to which COVID-19 may impact the Registrants' ability to operate their generating and transmission and distribution assets, the ability to access capital markets, and results of operations, including demand for electricity and natural gas, will depend on the spread and proliferation of COVID-19 around the world and future developments, which are highly uncertain and cannot be predicted at this time.

Financial Results of Operations

GAAP Results of Operations. The following table sets forth Exelon's GAAP consolidated Net Income attributable to common shareholders by Registrant for the three and nine months ended September 30, 2020 compared to the same period in 2019. For additional information regarding the financial results for the three and nine months ended September 30, 2020 and 2019 see the discussions of Results of Operations by Registrant.

	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Favorable (unfavorable) variance	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019	Favorable (unfavorable) variance
Exelon	$ 501	$ 772	$ (271)	$ 1,604	$ 2,164	$ (560)
Generation	49	257	(208)	570	728	(158)
ComEd	196	200	(4)	304	544	(240)
PECO	138	140	(2)	317	410	(93)
BGE	53	55	(2)	273	261	12
PHI	216	189	27	418	412	6
Pepco	118	98	20	227	217	10
DPL	27	33	(6)	91	116	(25)
ACE	75	63	12	106	87	19
Other[(a)]	(151)	(69)	(82)	(278)	(191)	(87)

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

Three Months Ended September 30, 2020 Compared to Three Months Ended September 30, 2019. **Net income attributable to common shareholders** decreased by $271 million and diluted earnings per average common share decreased to $0.51 in 2020 from $0.79 in 2019 primarily due to:

- Impairment of the New England asset group;
- One-time charges and accelerated depreciation and amortization associated with Generation's decisions in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021 and Mystic Units 8 and 9 in 2024, partially offset by the absence of accelerated depreciation and amortization due to the early retirement of TMI in September 2019;
- Reduction in load due to COVID-19 at Generation;
- COVID-19 direct costs; and
- Higher storm costs related to the August 2020 storm at PECO, net of tax repairs, and at DPL.

The decreases were partially offset by:

- Higher mark-to-market gains;
- Higher net unrealized gains on NDT funds;
- Lower operating and maintenance expense at Generation, primarily due to lower contracting and travel costs;
- Higher capacity revenue;
- Regulatory rate increases at BGE, DPL, and ACE; and
- Favorable weather conditions at PECO.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019. **Net income attributable to common shareholders** decreased by $560 million and diluted earnings per average common share decreased to $1.64 in 2020 from $2.22 in 2019 primarily due to:

- Impairment of the New England asset group;
- One-time charges and accelerated depreciation and amortization associated with Generation's decisions in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021 and Mystic Units 8 and 9 in 2024, partially offset by the absence of accelerated depreciation and amortization due to the early retirement of TMI in September 2019;
- Payments that ComEd will make under the Deferred Prosecution Agreement. See Note 14 - Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information;
- Lower net unrealized and realized gains on NDT funds;
- Lower capacity revenue;
- Higher nuclear outage days;
- Reduction in load due to COVID-19 at Generation;
- COVID-19 direct costs;
- Lower allowed electric distribution ROE at ComEd due to a decrease in treasury rates;
- Higher storm costs related to the June 2020 and August 2020 storms at PECO, net of tax repairs, and related to the August 2020 storm at DPL;
- Unfavorable weather conditions at PECO, DPL Delaware, and ACE; and
- A net increase in depreciation and amortization expense due to ongoing capital expenditures at PECO, BGE, Pepco, DPL, and ACE, partially offset at Generation due to the impact of extending the operating license at Peach Bottom.

The decreases were partially offset by:

- Higher mark-to-market gains;
- Lower operating and maintenance expense at Generation, primarily due to previous cost management programs, lower contracting costs, and lower travel costs;
- Lower nuclear fuel costs;
- The approval of the New Jersey ZEC program in the second quarter of 2019;
- An income tax settlement at Generation; and
- Regulatory rate increases at BGE, DPL, and ACE.

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

The following tables provide a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the three and nine months ended September 30, 2020 compared to the same period in 2019.

	Three Months Ended September 30,			
	2020		2019	
(In millions, except per share data)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$ 501	$ 0.51	$ 772	$ 0.79
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $62 and $2, respectively)	(183)	(0.19)	(2)	—
Unrealized Gains Related to NDT Fund Investments (net of taxes of $161 and $34, respectively)[(a)]	(172)	(0.18)	(39)	(0.04)
Asset Impairments (net of taxes of $126 and $53, respectively)[(b)]	375	0.38	113	0.12
Plant Retirements and Divestitures (net of taxes of $111 and $40, respectively)[(c)]	329	0.34	119	0.12
Cost Management Program (net of taxes of $5 and $3, respectively)[(d)]	15	0.02	14	0.01
Change in Environmental Liabilities (net of taxes of $6 and $5, respectively)	17	0.02	18	0.02
COVID-19 Direct Costs (net of taxes of $3)[(e)]	10	0.01	—	—
Asset Retirement Obligation (net of taxes of $1 and $9, respectively)[(f)]	3	—	(84)	(0.09)
Acquisition Related Costs (net of taxes of $1)[(g)]	2	—	—	—
Income Tax-Related Adjustments (entire amount represents tax expense)[(h)]	62	0.06	13	0.01
Noncontrolling Interests (net of taxes of $12 and $3, respectively)[(i)]	57	0.06	(24)	(0.02)
Adjusted (non-GAAP) Operating Earnings	$ 1,017	$ 1.04	$ 900	$ 0.92

(In millions, except per share data)	Nine Months Ended September 30, 2020	Earnings per Diluted Share	2019	Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$ 1,604	$ 1.64	$ 2,164	$ 2.22
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $112 and $31, respectively)	(329)	(0.34)	97	0.10
Unrealized (Gains) Losses Related to NDT Fund Investments (net of taxes of $31 and $167, respectively)[a]	8	0.01	(181)	(0.19)
Asset Impairments (net of taxes of $134 and $54, respectively)[b]	396	0.40	119	0.12
Plant Retirements and Divestitures (net of taxes of $117 and $9, respectively)[c]	348	0.36	114	0.12
Cost Management Program (net of taxes of $11 and $10, respectively)[d]	34	0.03	31	0.03
Litigation Settlement Gain (net of taxes of $7)	—	—	(19)	(0.02)
Change in Environmental Liabilities (net of taxes of $6 and $5, respectively)	18	0.02	18	0.02
COVID-19 Direct Costs (net of taxes of $13)[e]	37	0.04	—	—
Deferred Prosecution Agreement Payments (net of taxes of $0)[j]	200	0.20	—	—
Asset Retirement Obligation (net of taxes of $1 and $9, respectively)[f]	3	—	(84)	(0.09)
Acquisition Related Costs (net of tax of $1)[g]	2	—	—	—
Income Tax-Related Adjustments (entire amount represents tax expense)[h]	66	0.07	13	0.01
Noncontrolling Interests (net of taxes of $2 and $18, respectively)[i]	17	0.02	58	0.06
Adjusted (non-GAAP) Operating Earnings	$ 2,403	$ 2.46	$ 2,329	$ 2.39

____
Note:
Amounts may not sum due to rounding.
Unless otherwise noted, the income tax impact of each reconciling item between GAAP Net Income and Adjusted (non-GAAP) Operating Earnings is based on the marginal statutory federal and state income tax rates for each Registrant, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. For all items except the unrealized gains and losses related to NDT fund investments, the marginal statutory income tax rates for 2020 and 2019 ranged from 26.0% to 29.0%. Under IRS regulations, NDT fund investment returns are taxed at different rates for investments if they are in qualified or non-qualified funds. The effective tax rates for the unrealized gains and losses related to NDT fund investments were 48.3% and 47.1% for the three months ended September 30, 2020 and 2019, respectively. The effective tax rates for the unrealized gains and losses related to NDT fund investments were 134.1% and 48.1% for the nine months ended September 30, 2020 and 2019, respectively.

(a) Reflects the impact of net unrealized gains on Generation's NDT fund investments for Non-Regulatory and Regulatory Agreement Units. The impacts of the Regulatory Agreement Units, including the associated income taxes, are contractually eliminated, resulting in no earnings impact.
(b) In 2020, primarily reflects an impairment in the New England asset group. In 2019, primarily reflects the impairment of equity method investments in certain distributed energy companies. The impact of such impairment net of noncontrolling interest is $0.02.
(c) In 2020, primarily reflects one-time charges and accelerated depreciation and amortization associated with Generation's decisions in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021 and Mystic Units 8 and 9 in 2024. In 2019, primarily reflects accelerated depreciation and amortization expenses associated with the early retirement of the TMI nuclear facility and certain fossil sites, a charge associated with a remeasurement of the TMI ARO and the loss on sale of Oyster Creek to Holtec.
(d) Primarily represents reorganization and severance costs related to cost management programs.
(e) 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.
(f) In 2019, reflects a benefit related to Generation's annual nuclear ARO update for non-regulatory units.
(g) Reflects costs related to the acquisition of EDF's interest in CENG.

(h) Primarily reflects the adjustment to deferred income taxes due to changes in forecasted apportionment.
(i) Represents elimination from Generation's results of the noncontrolling interests related to certain exclusion items. In 2020, primarily related to unrealized gains and losses on NDT fund investments for CENG units. In 2019, primarily related to the impact of the impairment of equity investments in distributed energy companies, partially offset by the impact of Generation's annual nuclear ARO update and unrealized gains on NDT fund investments for CENG units.
(j) Reflects the payments that ComEd will make under the Deferred Prosecution Agreement. See Note 14 - Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Significant 2020 Transactions and Developments

Early Retirement of Generation Facilities

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

The following table summarizes the incremental expense recorded in the third quarter of 2020 and the estimated amounts of incremental expense expected to be incurred for full year 2020 and through the retirement dates.

		Projected[a]				
Income statement expense (pre-tax)	Three and Nine Months Ended September 30, 2020	2020	2021	2022	2023	2024
Depreciation and amortization						
Accelerated depreciation[b]	$ 260	$ 930	$ 2,110	$ 105	$ 115	$ 50
Accelerated nuclear fuel amortization	14	60	180	—	—	—
Operating and maintenance						
One-time charges	263	265	20	—	—	—
Other charges[c]	34	40	5	5	5	—
Contractual offset[d]	(129)	(370)	(755)	—	—	—
Total	$ 442	$ 925	$ 1,560	$ 110	$ 120	$ 50

(a) Actual results may differ based on incremental future capital additions, actual units of production for nuclear fuel amortization, future revised ARO assumptions, etc.
(b) Reflects incremental accelerated depreciation of plant assets, including any ARC.
(c) Reflects primarily the net impacts associated with the remeasurement of the ARO for Dresden. See Note 7 – Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional information.
(d) Reflects contractual offset for ARO accretion, ARC depreciation, and net impacts associated with the remeasurement of the ARO for Byron and Dresden. Based on the regulatory agreement with the ICC, decommissioning-related activities are offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset results in an equal adjustment to the noncurrent payables to ComEd at Generation and an adjustment to the regulatory liabilities at ComEd. See Note 9 – Asset Retirement Obligations of the Exelon 2019 Form 10-K for additional information.

Deferred Prosecution Agreement

On July 17, 2020, ComEd entered into a Deferred Prosecution Agreement (DPA) with the U.S. Attorney's Office for the Northern District of Illinois (USAO) to resolve the USAO's investigation into ComEd's lobbying activities in the State of Illinois. Under the DPA, the USAO filed a single charge alleging that ComEd improperly gave and offered to give jobs, vendor subcontracts, and payments associated with those jobs and subcontracts for the benefit of the Speaker of the Illinois House of Representatives and the Speaker's associates, with the intent to influence the Speaker's action regarding legislation affecting ComEd's interests. The DPA provides that the USAO will defer any prosecution of such charge and any other criminal or civil case against ComEd in connection with the matters identified therein for a three-year period subject to certain obligations of ComEd, including payment to the United States Treasury of $200 million, with $100 million payable within thirty days of the filing of the DPA with the United States District Court for the Northern District of Illinois and an additional $100 million within ninety days of such filing date. The payments will not be recovered in rates or charged to customers, and ComEd will not seek or accept reimbursement or indemnification from any source other than Exelon. See Note 14 — Commitments and Contingencies for additional information.

Utility Rates and Base Rate Proceedings

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

The following tables show the Utility Registrants' completed and pending distribution base rate case proceedings in 2020. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on these and other regulatory proceedings.

Completed Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement (Decrease) Increase	Approved Revenue Requirement (Decrease) Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois (Electric)	April 8, 2019	$ (6)	$ (17)	8.91 %	December 4, 2019	January 1, 2020
DPL - Maryland (Electric)	December 5, 2019 (amended April 23, 2020)	17	12	9.60 %	July 14, 2020	July 16, 2020

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement (Decrease) Increase	Requested ROE	Expected Approval Timing
ComEd - Illinois (Electric)	April 16, 2020	$ (11)	8.38 %	Fourth quarter of 2020
PECO - Pennsylvania (Natural Gas)	September 30, 2020	69	10.95 %	Second quarter of 2021
BGE - Maryland (Electric and Natural Gas)	May 15, 2020 (amended September 11, 2020)	228	10.1 %	Fourth quarter of 2020
Pepco - District of Columbia (Electric)	May 30, 2019 (amended June 1, 2020)	136	9.7 %	First quarter of 2021
Pepco - Maryland (Electric)	October 26, 2020	110	10.2 %	Second quarter of 2021
DPL - Delaware (Natural Gas)	February 21, 2020 (amended October 9, 2020)	7	10.3 %	First quarter of 2021
DPL - Delaware (Electric)	March 6, 2020 (amended October 26, 2020)	24	10.3 %	Second quarter of 2021

Transmission Formula Rates

Transmission Formula Rate (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE). ComEd’s, PECO's, BGE’s, Pepco's, DPL's, and ACE's transmission rates are each established based on a FERC-approved formula. ComEd, BGE, Pepco, DPL, and ACE are required to file an annual update to the FERC-approved formula on or before May 15 and PECO is required to file on or before May 31, with the resulting rates effective on June 1 of the same year. The annual update for ComEd, BGE, DPL, and ACE is based on prior year actual costs and current year projected capital additions (initial year revenue requirement). The annual update for PECO is based on prior year actual costs and current year projected capital additions, accumulated depreciation, and accumulated deferred income taxes. The annual update for Pepco is based on prior year actual costs and current year projected capital additions, accumulated depreciation, depreciation and amortization expense and accumulated deferred income taxes. The update for ComEd, BGE, DPL, and ACE also reconciles any differences between the revenue requirement in effect beginning June 1 of the prior year and actual costs incurred for that year (annual reconciliation). The update for PECO and Pepco also reconciles any differences between the actual costs and actual revenues for the calendar year (annual reconciliation).

For 2020, the following total increases/(decreases) were included in ComEd’s, PECO's, BGE’s, Pepco's, DPL's, and ACE's electric transmission formula rate filings:

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

Sales of Customer Accounts Receivable

On April 8, 2020, NER, a bankruptcy remote, special purpose entity, which is wholly owned by Generation, entered into an accounts receivable financing facility with a number of financial institutions and a commercial paper conduit to sell certain customer accounts receivables. Generation received approximately $500 million of cash in accordance with the initial sale of approximately $1.2 billion receivables. See Note 5 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.

Other Key Business Drivers and Management Strategies

The following discussion of other key business driver and management strategies includes current developments of previously disclosed matters and new issues arising during the period that may impact future financial statements. This section should be read in conjunction with ITEM 1. Business and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Other Key Business Drivers and Management Strategies in the Registrants' combined 2019 Form 10-K and Note 14 — Commitments and Contingencies to the Consolidated Financial Statements in this report for additional information on various environmental matters.

Power Markets

Section 232 Uranium Petition

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

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

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

Hedging Strategy

Exelon’s policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. As of September 30, 2020, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 97%-100% and 87%-90% for 2020 and 2021, respectively. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk.

Generation procures natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Approximately 60% of Generation’s uranium concentrate requirements from 2020 through 2024 are supplied by three suppliers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrate can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial positions.

See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements and Item 3. Quantitative and Qualitative Disclosures about Market Risk for additional information.

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

Environmental Legislative and Regulatory Developments

Air Quality

Mercury and Air Toxics Standards Rule (MATS). On December 16, 2011, the EPA signed a final rule, known as MATS, to reduce emissions of hazardous air pollutants from power plants. MATS requires coal-fired power plants to achieve high removal rates of mercury, acid gases, and other metals, and to make capital investments in pollution control equipment and incur higher operating expenses. In April 2014, the U.S. Court of Appeals for the D.C. Circuit issued a decision upholding MATS in its entirety. On appeal, the U.S. Supreme Court decided in June 2015 that the EPA unreasonably refused to consider costs in determining whether it is appropriate and necessary to regulate power plant emissions of hazardous air pollutants, but did not vacate MATS. In 2016, the EPA issued a supplemental finding responding to the U.S. Supreme Court's decision; the EPA concluded that, after considering costs, it remained appropriate and necessary to regulate hazardous air pollutants from power plants. On May 22, 2020, however, the EPA reversed course, publishing a final rule revoking the "appropriate and necessary" finding underpinning MATS. A coal mining company filed a lawsuit in the D.C. Circuit Court seeking vacatur of MATS based on EPA's May 22, 2020 ruling. On September 11, 2020, the court granted a motion by Exelon and two other entities to intervene in that lawsuit to defend MATS, and on September 28, 2020, the court issued an order holding this portion of MATS litigation in abeyance. On July 21, 2020, Exelon and two other entities filed a lawsuit in the D.C. Circuit Court challenging the EPA's May 22, 2020 rescission of the appropriate and necessary finding underpinning MATS; litigation on this portion of the case is ongoing.

The Clean Power Plan and Affordable Clean Energy Rule. The EPA's 2015 Clean Power Plan (CPP) established regulations addressing carbon dioxide emissions from existing fossil-fired power plants under Clean Air Act Section 111(d). The CPP's carbon pollution limits could be met through changes to the electric generation system, including shifting generation from higher-emitting units to lower- or zero-emitting units, as well as the development of new or expanded zero-emissions generation. In July 2019, the EPA published its final Affordable Clean Energy rule, which repealed the CPP and replaced it with less stringent emissions guidelines for existing coal-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 has been consolidated with separate challenges to the Affordable Clean Energy rule filed by various states, non-governmental organizations, and business coalitions.

Employees

In the second quarter of 2020, Generation, ComEd, and DPL ratified or extended CBAs as follows:

- Generation ratified its CBA with SPFPA Local 238, which covers 122 security officers at Quad Cities. The CBA expires in 2023.
- ComEd extended its CBA with IBEW Local 15 to 2022, which covers 80 employees in the System Services Group.
- DPL ratified its CBAs with IBEW Locals 1238 and 1307, which together cover 857 employees. Both CBAs expire in 2024.

In the third quarter of 2020, Generation ratified CBAs as follows:

- CBA with SEIU Local 1, which covers 102 security officers at LaSalle. The CBA expires in 2023.

- CBA with IBEW Local 614, which covers 74 employees at Conowingo, Eddystone, and Fairless. The CBA expires in 2023.

In the fourth quarter of 2020, Generation ratified CBAs as follows:

- CBA with UGSOA Local 12, which covers 113 security officers at Limerick. The CBA expires in 2025.
- CBA with IBEW Local 97, which covers 494 employees at Nine Mile Point. The CBA expires in 2025.

Critical Accounting Policies and Estimates

Management of each of the Registrants makes a number of significant estimates, assumptions, and judgments in the preparation of its financial statements. At September 30, 2020, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2019. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates in the Registrants' 2019 Form 10-K for further information.

Results of Operations by Registrant

Results of Operations — Generation

Generation’s Results of Operations includes discussion of RNF, which is a financial measure not defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. The CODMs for Exelon and Generation evaluate the performance of Generation's electric business activities and allocate resources based on RNF. Generation believes that RNF is a useful measure because it provides information that can be used to evaluate its operational performance.

	Three Months Ended September 30,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2020	2019		2020	2019	
Operating revenues	$ 4,659	$ 4,774	$ (115)	$ 13,272	$ 14,280	$ (1,008)
Purchased power and fuel expense	2,314	2,651	337	6,961	8,148	1,187
Revenues net of purchased power and fuel expense	2,345	2,123	222	6,311	6,132	179
Other operating expenses						
Operating and maintenance	1,737	1,087	(650)	4,188	3,570	(618)
Depreciation and amortization	558	407	(151)	1,161	1,221	60
Taxes other than income taxes	118	129	11	364	394	30
Total other operating expenses	2,413	1,623	(790)	5,713	5,185	(528)
(Loss) Gain on sales of assets and businesses	—	(18)	18	12	15	(3)
Operating (loss) income	(68)	482	(550)	610	962	(352)
Other income and (deductions)						
Interest expense, net	(80)	(109)	29	(277)	(336)	59
Other, net	367	128	239	199	729	(530)
Total other income and (deductions)	287	19	268	(78)	393	(471)
Income before income taxes	219	501	(282)	532	1,355	(823)
Income taxes	100	87	(13)	41	388	347
Equity in losses of unconsolidated affiliates	(2)	(170)	168	(6)	(183)	177
Net income	117	244	(127)	485	784	(299)
Net income (loss) attributable to noncontrolling interests	68	(13)	81	(85)	56	(141)
Net income attributable to membership interest	$ 49	$ 257	$ (208)	$ 570	$ 728	$ (158)

Three Months Ended September 30, 2020 Compared to Three Months Ended September 30, 2019. **Net income attributable to membership interest** decreased $208 million by primarily due to:

- Impairment of the New England asset group;
- One-time charges and accelerated depreciation and amortization associated with Generation's decisions in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021 and

Mystic Units 8 and 9 in 2024, partially offset by the absence of accelerated depreciation and amortization due to the early retirement of TMI in September 2019;

- Reduction in load due to COVID-19; and
- COVID-19 direct costs.

The decreases were partially offset by:

- Higher mark-to-market gains;
- Higher net unrealized gains on NDT funds;
- Lower operating and maintenance expense primarily due to lower contracting and travel costs; and
- Higher capacity revenue.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019. **Net income attributable to membership interest** decreased $158 million by primarily due to:

- Impairment of the New England asset group;
- One-time charges and accelerated depreciation and amortization associated with Generation's decisions in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021 and Mystic Units 8 and 9 in 2024, partially offset by the absence of accelerated depreciation and amortization due to the early retirement of the TMI in September 2019;
- Lower net unrealized and realized gains on NDT funds;
- Lower capacity revenue;
- Higher nuclear outage days;
- Reduction in load due to COVID-19; and
- COVID-19 direct costs.

The decreases were partially offset by:

- Higher mark-to-market gains;
- Lower operating and maintenance expense primarily due to previous cost management programs, lower contracting costs, and lower travel costs;
- Lower depreciation and amortization expense due to the impact of extending the operating license at Peach Bottom;
- Lower nuclear fuel costs;
- The approval of the New Jersey ZEC program in the second quarter of 2019; and
- An income tax settlement.

Revenues Net of Purchased Power and Fuel Expense. The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned with these same geographic regions. Generation's five reportable segments are Mid-

Atlantic, Midwest, New York, ERCOT, and Other Power Regions. See Note 4 - Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on these reportable segments.

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

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

For the three and nine months ended September 30, 2020 compared to 2019, RNF by region were as follows. See Note 4 - Segment Information of the Combined Notes to the Consolidated Financial Statements for additional information on Purchase power and fuel expense for Generation's reportable segments.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2020	2019	Variance	% Change	2020	2019	Variance	% Change
Mid-Atlantic[(a)]	$ 591	$ 689	$ (98)	(14.2)%	$ 1,683	$ 2,023	$ (340)	(16.8)%
Midwest[(b)]	750	747	3	0.4 %	2,178	2,247	(69)	(3.1)%
New York	285	291	(6)	(2.1)%	725	810	(85)	(10.5)%
ERCOT	147	72	75	104.2 %	325	225	100	44.4 %
Other Power Regions	225	184	41	22.3 %	538	478	60	12.6 %
Total electric revenues net of purchased power and fuel expense	1,998	1,983	15	0.8 %	5,449	5,783	(334)	(5.8)%
Mark-to-market gains (losses)	255	17	238	1,400.0 %	472	(84)	556	661.9 %
Other	92	123	(31)	(25.2)%	390	433	(43)	(9.9)%
Total revenue net of purchased power and fuel expense	$ 2,345	$ 2,123	$ 222	10.5 %	$ 6,311	$ 6,132	$ 179	2.9 %

(a) Includes results of transactions with PECO, BGE, Pepco, DPL, and ACE.
(b) Includes results of transactions with ComEd.

Generation's supply sources by region are summarized below:

Supply Source (GWhs)	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Variance	% Change	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019	Variance	% Change
Nuclear Generation[a]								
Mid-Atlantic	13,679	15,281	(1,602)	(10.5)%	39,630	44,436	(4,806)	(10.8)%
Midwest	24,471	23,730	741	3.1 %	71,929	71,459	470	0.7 %
New York	6,734	7,204	(470)	(6.5)%	19,296	20,783	(1,487)	(7.2)%
Total Nuclear Generation	44,884	46,215	(1,331)	(2.9)%	130,855	136,678	(5,823)	(4.3)%
Fossil and Renewables								
Mid-Atlantic	304	485	(181)	(37.3)%	1,864	2,351	(487)	(20.7)%
Midwest	196	262	(66)	(25.2)%	852	981	(129)	(13.1)%
New York	1	3	(2)	(66.7)%	3	4	(1)	(25.0)%
ERCOT	4,394	4,500	(106)	(2.4)%	10,658	10,644	14	0.1 %
Other Power Regions	2,794	3,135	(341)	(10.9)%	8,905	8,789	116	1.3 %
Total Fossil and Renewables	7,689	8,385	(696)	(8.3)%	22,282	22,769	(487)	(2.1)%
Purchased Power								
Mid-Atlantic	8,252	5,235	3,017	57.6 %	17,924	10,359	7,565	73.0 %
Midwest	71	124	(53)	(42.7)%	595	662	(67)	(10.1)%
ERCOT	1,104	1,329	(225)	(16.9)%	3,351	3,585	(234)	(6.5)%
Other Power Regions	14,512	13,006	1,506	11.6 %	37,981	36,693	1,288	3.5 %
Total Purchased Power	23,939	19,694	4,245	21.6 %	59,851	51,299	8,552	16.7 %
Total Supply/Sales by Region[c]								
Mid-Atlantic[b]	22,235	21,001	1,234	5.9 %	59,418	57,146	2,272	4.0 %
Midwest[b]	24,738	24,116	622	2.6 %	73,376	73,102	274	0.4 %
New York	6,735	7,207	(472)	(6.5)%	19,299	20,787	(1,488)	(7.2)%
ERCOT	5,498	5,829	(331)	(5.7)%	14,009	14,229	(220)	(1.5)%
Other Power Regions	17,306	16,141	1,165	7.2 %	46,886	45,482	1,404	3.1 %
Total Supply/Sales by Region	76,512	74,294	2,218	3.0 %	212,988	210,746	2,242	1.1 %

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g. CENG).
(b) Includes affiliate sales to PECO, BGE, Pepco, DPL, and ACE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region.
(c) Reflects a decrease in load due to COVID-19.

For the three and nine months ended September 30, 2020 compared to 2019, changes in **RNF** by region were as follows:

	Increase/ (Decrease)	Three Months Ended September 30, 2020	Increase/ (Decrease)	Nine Months Ended September 30, 2020
Mid-Atlantic	$ (98)	• decreased revenue due to permanent cease of generation operations at TMI in the third quarter of 2019 • lower realized energy prices, partially offset by • increase in new contracted load, offset by impacts of COVID-19 • increased capacity revenue	$ (340)	• decreased revenue due to permanent cease of generation operations at TMI in the third quarter of 2019 • decreased capacity revenue • lower realized energy prices, partially offset by • increase in new contracted load, offset by impacts of COVID-19 • increased ZEC revenues due to the approval of the NJ ZEC program in the second quarter of 2019
Midwest	3	• increase in total ISO sales offset by impacts of COVID-19 • decreased nuclear outage days • increased capacity revenue, partially offset by • lower realized energy prices	(69)	• decreased capacity revenue • lower realized energy prices, partially offset by • increase in total ISO sales offset by impacts of COVID-19 • decreased nuclear outage days
New York	(6)	• increased nuclear outage days • decreased ZEC revenues due to increased nuclear outage days • lower realized energy prices, partially offset by • increase in new contracted load, offset by impacts of COVID-19 • increased capacity revenue	(85)	• increased nuclear outage days • decreased ZEC revenues due to increased nuclear outage days • lower realized energy prices, • decreased load due to COVID-19 offset by new contracted load, partially offset by • increased capacity revenue
ERCOT	75	• higher portfolio optimization • lower procurement costs for owned and contracted assets	100	• higher portfolio optimization • lower procurement costs for owned and contracted assets
Other Power Regions	41	• increase in new contracted load, offset by impacts of COVID-19 • higher portfolio optimization, partially offset by • decreased capacity revenue • lower realized energy prices	60	• increase in new contracted load, offset by impacts of COVID-19 • higher portfolio optimization, partially offset by • decreased capacity revenue • lower realized energy prices
Mark-to-market[(a)]	238	• gains on economic hedging activities of $255 million in 2020 compared to gains of $17 million in 2019	556	• gains on economic hedging activities of $472 million in 2020 compared to losses of $84 million in 2019
Other	(31)	• decreased revenue related to the energy efficiency business • increase in accelerated nuclear fuel amortization associated with announced early plant retirements	(43)	• decreased revenue related to the energy efficiency business • increase in accelerated nuclear fuel amortization associated with announced early plant retirements
Total	$ 222		$ 179	

(a) See Note 11 — Derivative Financial Instruments for additional information on mark-to-market gains (losses).

Nuclear Fleet Capacity Factor. The following table presents nuclear fleet operating data for the Generation-operated plants, which reflects ownership percentage of stations operated by Exelon, excluding Salem, which is operated by PSEG. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Generation considers capacity factor to be a useful measure to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Nuclear fleet capacity factor	96.0 %	95.5 %	95.1 %	95.9 %
Refueling outage days	17	15	203	145
Non-refueling outage days	4	15	15	43

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

	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2020
	Increase (Decrease)	Increase (Decrease)
Asset impairments	$ 499	$ 504
Plant retirements and divestitures	137	206
ARO update	65	65
Change in environmental liabilities	22	24
COVID-19 direct costs	10	33
Credit loss expense[(a)]	2	19
Litigation settlements	—	26
Nuclear refueling outage costs, including the co-owned Salem plants	(3)	52
Accretion expense	(5)	(20)
Pension and non-pension postretirement benefits expense	(6)	(15)
Corporate allocations	(12)	(40)
Travel costs	(13)	(25)
Labor, other benefits, contracting and materials[(b)]	(39)	(196)
Other	(7)	(15)
Increase in operating and maintenance expense	$ 650	$ 618

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

Depreciation and amortization expense for the three months ended September 30, 2020 compared to the same period in 2019 increased primarily due to the accelerated depreciation and amortization associated with Generation's decision to early retire the Byron and Dresden nuclear facilities and for the nine months ended September 30, 2020 compared to the same period in 2019 decreased primarily due to the permanent cease of generation operations at TMI partially offset by the accelerated depreciation and amortization associated with Generation's decision to early retire the Byron and Dresden nuclear facilities.

Taxes other than income taxes for the three and nine months ended September 30, 2020 compared to the same period in 2019 decreased primarily due to decreased sales and power usage.

(Loss) Gain on sales of assets and businesses for the three months ended September 30, 2020 compared to the same period in 2019 increased primarily due to a loss on Generation's sale of Oyster Creek in the third quarter of 2019 and for the nine months ended September 30, 2020 compared to the same period in 2019 decreased primarily due to Generation's gain on sale of certain wind assets in the second quarter of 2019 partially offset by the loss on sale of Oyster Creek.

Interest Expense for the three and nine months ended September 30, 2020 compared to the same period in 2019 decreased primarily due to the redemption of long-term debt in 2020.

Other, net for the three months ended September 30, 2020 compared to the same period in 2019 increased and for the nine months ended September 30, 2020 compared to the same period in 2019 decreased due to activity associated with NDT funds as described in the table below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	2020	2019
Net unrealized gains on NDT funds[a]	$ 254	$ 55	$ 1	$ 236
Net realized gains on sale of NDT funds[a]	—	9	58	231
Interest and dividend income on NDT funds[a]	23	24	69	85
Contractual elimination of income tax expense[b]	89	31	46	150
Other	1	9	25	27
Total other, net	$ 367	$ 128	$ 199	$ 729

(a) Unrealized gains, realized gains and interest and dividend income on the NDT funds are associated with the Non-Regulatory Agreement Units.
(b) Contractual elimination of income tax expense is associated with the income taxes on the NDT funds of the Regulatory Agreement Units.

Effective income tax rates were 45.7% and 17.4% for the three months ended September 30, 2020 and 2019, respectively. Generation's effective income tax rates were 7.7% and 28.6% for the nine months ended September 30, 2020 and 2019, respectively. The change primarily relates to one-time tax settlements and an increase in tax credits. See Note 9 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information

Equity in losses of unconsolidated affiliates for the three and nine months ended September 30, 2020 compared to the same period in 2019 increased primarily due to the impairment of equity method investments in certain distributed energy companies in the third quarter of 2019.

Net income attributable to noncontrolling interests for the three months ended September 30, 2020 compared to the same period in 2019 increased primarily due to higher net gains on NDT fund investments for CENG and for the nine months ended September 30, 2020 compared to the same period in 2019 decreased primarily due to lower unrealized losses on NDT fund investments for CENG.

Results of Operations — ComEd

	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019	Favorable (Unfavorable) Variance
Operating revenues	$ 1,643	$ 1,583	$ 60	$ 4,499	$ 4,342	$ 157
Operating expenses						
Purchased power expense	606	577	(29)	1,557	1,469	(88)
Operating and maintenance	321	340	19	1,173	967	(206)
Depreciation and amortization	294	259	(35)	841	767	(74)
Taxes other than income taxes	81	80	(1)	227	228	1
Total operating expenses	1,302	1,256	(46)	3,798	3,431	(367)
Gain on sales of assets	—	1	(1)	—	4	(4)
Operating income	341	328	13	701	915	(214)
Other income and (deductions)						
Interest expense, net	(95)	(91)	(4)	(287)	(268)	(19)
Other, net	10	8	2	32	27	5
Total other income and (deductions)	(85)	(83)	(2)	(255)	(241)	(14)
Income before income taxes	256	245	11	446	674	(228)
Income taxes	60	45	(15)	142	130	(12)
Net income	$ 196	$ 200	$ (4)	$ 304	$ 544	$ (240)

Three Months Ended September 30, 2020 Compared to Three Months Ended September 30, 2019. **Net income** remained relatively consistent for the three months ended September 30, 2020 compared to the same period in 2019.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019. **Net income** decreased $240 million as compared to the same period in 2019, primarily due to payments that ComEd will make under the Deferred Prosecution Agreement, an impairment charge resulting from acquisition of transmission assets, and lower allowed electric distribution ROE due to a decrease in treasury rates, partially offset by higher electric distribution formula rate earnings (reflecting the impacts of higher rate base). See Note 14 — 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:

	Three Months Ended September 30, 2020 Increase	Nine Months Ended September 30, 2020 Increase (Decrease)
Electric distribution	$ 11	$ 31
Transmission	8	(4)
Energy efficiency	10	29
Other	16	21
	45	77
Regulatory required programs	15	80
Total increase	$ 60	$ 157

Revenue Decoupling. The demand for electricity is affected by weather conditions and customer usage. Operating revenues are not impacted by abnormal weather, usage per customer or number of customers as a result of the electric distribution formula rate pursuant to FEJA.

Distribution Revenue. EIMA and FEJA provide for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Electric distribution revenue varies from year to year based upon fluctuations in the underlying costs, (e.g., severe weather and storm restoration), investments being recovered, and allowed ROE. Electric distribution revenue increased for the three and nine months ended September 30, 2020 as compared to the same period in 2019, due to the impact of higher rate base and higher fully recoverable costs, offset by lower allowed ROE due to a decrease in treasury rates. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered, and the highest daily peak load, which is updated annually in January based on the prior calendar year. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. Transmission revenue increased for the three months ended September 30, 2020 compared to the same period in 2019, primarily due to increased peak load and higher fully recoverable costs. Transmission revenue decreased for the nine months ended September 30, 2020 compared to the same period in 2019, primarily due to the impact of decreased peak load partially offset by higher fully recoverable costs. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Energy Efficiency Revenue. FEJA provides for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Under FEJA, energy efficiency revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, and allowed ROE. Energy efficiency revenue increased during the three and nine months ended September 30, 2020 as compared to the same period in 2019, primarily due to increased regulatory asset amortization which is fully recoverable. See Depreciation and amortization expense discussions below and Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other Revenue primarily includes assistance provided to other utilities through mutual assistance programs. The increase in Other revenue for the three and nine months ended September 30, 2020 as compared to the same period in 2019, primarily reflects mutual assistance revenues associated with storm restoration efforts.

Regulatory Required Programs represents revenues collected under approved riders to recover costs incurred for regulatory programs such as recoveries under the credit loss expense tariff, environmental costs associated with MGP sites, and costs related to electricity, ZEC and REC procurement. The riders are designed to provide full and current cost recovery. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries but impact Operating revenues related to supplied electricity. Drivers of Operating revenues related to electricity, ZEC and REC procurement costs, and participation in customer choice programs are fully offset by their impact on Purchased power and fuel expense. ComEd recovers electricity, ZEC, and REC procurement costs from customers without mark-up.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ComEd's revenue disaggregation.

The increase of $29 million and $88 million for the three and nine months ended September 30, 2020 compared to the same period in 2019, respectively, in **Purchased power expense** is offset in Operating revenues as part of regulatory required programs.

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

	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2020
	Increase (Decrease)	(Decrease) Increase
Labor, other benefits, contracting and materials	$ 2	$ (7)
Pension and non-pension postretirement benefits expense	1	5
Deferred Prosecution Agreement payments[(a)]	—	200
BSC costs	(7)	9
Storm-related costs[(b)]	(12)	(10)
Other[(c)]	1	11
	(15)	208
Regulatory required programs[(d)]	(4)	(2)
Total (decrease) increase	$ (19)	$ 206

____
(a) See Note 14 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.
(b) For the three and nine months ended September 30, 2020, the decrease primarily reflects lower storm costs as a result of the August 2020 storm costs being reclassified to a regulatory asset.
(c) For the nine months ended September 30, 2020, the increase primarily reflects impairment charge related to acquisition of transmission assets.
(d) ComEd is allowed to recover from or refund to customers the difference between its annual credit loss expense and the amounts collected in rates annually through a rider mechanism. During the three and nine months ended September 30, 2020, ComEd recorded a net decrease in credit losses account due to the timing of regulatory cost recovery. An equal and offsetting amount has been recognized in Operating revenues for the period presented.

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

	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2020
	Increase	Increase
Depreciation and amortization[(a)]	$ 30	$ 58
Regulatory asset amortization[(b)]	5	16
Total increase	$ 35	$ 74

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

Effective income tax rates were 23.4% and 18.4% for the three months ended September 30, 2020 and 2019, respectively, and 31.8% and 19.3% for the nine months ended September 30, 2020 and 2019, respectively. See Note 9 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations — PECO

	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019	Favorable (Unfavorable) Variance
Operating revenues	$ 813	$ 778	$ 35	$ 2,306	$ 2,333	$ (27)
Operating expenses						
Purchased power and fuel expense	269	246	(23)	768	767	(1)
Operating and maintenance	251	219	(32)	742	643	(99)
Depreciation and amortization	85	83	(2)	259	247	(12)
Taxes other than income taxes	53	47	(6)	131	126	(5)
Total operating expenses	658	595	(63)	1,900	1,783	(117)
Operating income	155	183	(28)	406	550	(144)
Other income and (deductions)						
Interest expense, net	(39)	(33)	(6)	(108)	(100)	(8)
Other, net	6	4	2	12	11	1
Total other income and (deductions)	(33)	(29)	(4)	(96)	(89)	(7)
Income before income taxes	122	154	(32)	310	461	(151)
Income taxes	(16)	14	30	(7)	51	58
Net income	$ 138	$ 140	$ (2)	$ 317	$ 410	$ (93)

Three Months Ended September 30, 2020 Compared to Three Months Ended September 30, 2019. **Net income** remained relatively consistent primarily due to favorable weather conditions, offset by higher storm costs due to the August 2020 storm net of tax repairs.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019. **Net income** decreased by $93 million primarily due to unfavorable weather conditions, higher storm costs due to the June and August 2020 storms net of tax repairs, increased depreciation and amortization expense, and an increase in credit loss expense primarily as a result of suspending customer disconnections offset by the regulatory asset recorded in the third quarter of 2020 related to incremental credit loss expense due to COVID-19.

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

	Three Months Ended September 30, 2020 Increase (Decrease)			Nine Months Ended September 30, 2020 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$ 9	$ 1	$ 10	$ (15)	$ (12)	$ (27)
Volume	6	1	7	1	(6)	(5)
Pricing	(6)	(3)	(9)	2	2	4
Transmission	7	—	7	9	—	9
Other	(1)	—	(1)	(6)	(1)	(7)
	15	(1)	14	(9)	(17)	(26)
Regulatory required programs	27	(6)	21	54	(55)	(1)
Total increase (decrease)	$ 42	$ (7)	$ 35	$ 45	$ (72)	$ (27)

Weather. The demand for electricity and natural gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as “favorable weather conditions” because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the three months ended September 30, 2020 compared to the same period in 2019, Operating revenues related to weather increased by the impact of favorable weather conditions in PECO's service territory. During the nine months ended September 30, 2020 compared to the same period in 2019, Operating revenues related to weather decreased by the impact of unfavorable weather conditions in PECO's service territory.

Heating and cooling degree-days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree-days for a 30-year period in PECO's service territory. The changes in heating and cooling degree-days in PECO's service territory for the three and nine months ended September 30, 2020 compared to the same period in 2019 and normal weather consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended September 30,	2020	2019	Normal	From 2019	2020 vs. Normal
Heating Degree-Days	37	2	26	1,750.0 %	42.3 %
Cooling Degree-Days	1,128	1,143	1,004	(1.3)%	12.4 %
Nine Months Ended September 30,					
Heating Degree-Days	2,594	2,704	2,876	(4.1)%	(9.8)%
Cooling Degree-Days	1,504	1,570	1,391	(4.2)%	8.1 %

Volume. Electric volume, exclusive of the effects of weather, for the three months ended September 30, 2020, compared to the same period in 2019, increased on a net basis due to an increase in usage for residential customers during COVID-19 further increased by customer growth. Electric volume, exclusive of the effects of weather, for the nine months ended September 30, 2020, compared to the same period in 2019, remained relatively consistent. Natural gas volume for the three months ended September 30, compared to the same period in 2019, remained relatively consistent. Natural gas volume for the nine months ended September 30, compared to the same period in 2019, decreased on a net basis due to a decrease in usage for the commercial and industrial natural gas classes during COVID-19.

Electric Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30,		% Change	Weather - Normal % Change[b]	Nine Months Ended September 30,		% Change	Weather - Normal % Change[b]
	2020	2019			2020	2019		
Residential	4,477	4,106	9.0 %	6.4 %	10,874	10,568	2.9 %	4.5 %
Small commercial & industrial	2,017	2,203	(8.4)%	(9.4)%	5,493	6,093	(9.8)%	(8.4)%
Large commercial & industrial	3,791	4,109	(7.7)%	(8.3)%	10,393	11,449	(9.2)%	(8.9)%
Public authorities & electric railroads	145	183	(20.8)%	(20.8)%	407	560	(27.3)%	(27.2)%
Total electric retail deliveries[a]	10,430	10,601	(1.6)%	(3.2)%	27,167	28,670	(5.2)%	(4.2)%

	As of September 30,	
Number of Electric Customers	2020	2019
Residential	1,505,080	1,489,046
Small commercial & industrial	154,183	153,400
Large commercial & industrial	3,105	3,104
Public authorities & electric railroads	10,149	9,775
Total	1,672,517	1,655,325

(a) Reflects delivery volumes from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.
(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 30-year average.

Natural Gas Deliveries to Customers (in mmcf)	Three Months Ended September 30, 2020	2019	% Change	Weather - Normal % Change[(b)]	Nine Months Ended September 30, 2020	2019	% Change	Weather - Normal % Change[(b)]
Residential	2,121	2,109	0.6 %	(4.3)%	25,867	26,678	(3.0)%	0.7 %
Small commercial & industrial	2,157	1,901	13.5 %	12.7 %	13,020	16,585	(21.5)%	(8.0)%
Large commercial & industrial	9	10	(10.0)%	(13.4)%	20	46	(56.5)%	(16.5)%
Transportation	5,269	5,395	(2.3)%	(4.2)%	17,553	19,087	(8.0)%	(6.9)%
Total natural gas retail deliveries[(a)]	9,556	9,415	1.5 %	(1.1)%	56,460	62,396	(9.5)%	(3.8)%

Number of Natural Gas Customers	As of September 30, 2020	2019
Residential	490,158	484,676
Small commercial & industrial	44,138	43,869
Large commercial & industrial	5	2
Transportation	715	735
Total	535,016	529,282

(a) Reflects delivery volumes from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges.
(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 30-year average.

Pricing for the three months ended September 30, 2020 compared to the same period in 2019 decreased primarily due to lower overall effective rates due to increased usage across all major customer classes. Pricing for the nine months ended September 30, 2020 compared to the same period in 2019 remained relatively consistent.

Transmission Revenue. Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. PECO's transmission formula rate filing was approved in the fourth quarter of 2019.

Regulatory Required Programs represents revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency, PGC, and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense, and Income taxes. Customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. Customer choice programs do not impact the volume of deliveries but impact Operating revenues related to supplied electricity and natural gas. Drivers of Operating revenues related to commodity and REC procurement costs and participation in customer choice programs are fully offset by their impact on Purchased power and fuel expense. PECO recovers electricity, natural gas, and REC procurement costs from customers without mark-up.

Other revenue primarily includes revenue related to late payment charges. Other revenues for the three and nine months ended September 30, 2020 compared to the same period in 2019, decreased as PECO ceased new late fees for all customers and restored service to customers upon request who were disconnected in the last twelve months beginning March of 2020.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of PECO's revenue disaggregation.

The increase of $23 million and $1 million for the three and nine months ended September 30, 2020 compared to the same period in 2019, respectively, in **Purchased power and fuel expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2020
	Increase (Decrease)	(Decrease) Increase
Storm-related costs[(a)]	$ 28	$ 81
Labor, other benefits, contracting and materials	13	9
Pension and non-pension postretirement benefits expense	(1)	(2)
Credit loss expense[(b)]	(3)	16
Other	(5)	(5)
Total increase	$ 32	$ 99

(a) Reflects increased storm costs due to June and August 2020 storms.
(b) Increased credit loss expense for the nine months ended September 30, 2020 primarily as a result of suspending customer disconnections offset by the regulatory asset recorded in the third quarter of 2020 related to incremental credit loss expense, due to COVID-19. Decreased credit loss expense for the three months ended September 30, 2020 is due to the reversal of credit loss expense when the regulatory asset was recorded. See Note 2 - Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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

	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2020
	Increase	Increase (Decrease)
Depreciation and amortization[(a)]	$ 2	$ 13
Regulatory asset amortization	—	(1)
Total increase	$ 2	$ 12

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

Interest expense, net increased $6 million and $8 million for the three and nine months ended September 30, 2020 compared to the same period in 2019, respectively, primarily due to the issuance of debt in June 2020.

Effective income tax rates were (13.1)% and 9.1% for the three months ended September 30, 2020 and 2019, respectively, and (2.3)% and 11.1% for the nine months ended September 30, 2020 and 2019, respectively. See Note 9 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations — BGE

	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019	Favorable (Unfavorable) Variance
Operating revenues	$ 731	$ 703	$ 28	$ 2,284	$ 2,327	$ (43)
Operating expenses						
Purchased power and fuel expense	250	235	(15)	731	804	73
Operating and maintenance	191	196	5	567	569	2
Depreciation and amortization	133	116	(17)	405	368	(37)
Taxes other than income taxes	68	65	(3)	200	195	(5)
Total operating expenses	642	612	(30)	1,903	1,936	33
Operating income	89	91	(2)	381	391	(10)
Other income and (deductions)						
Interest expense, net	(34)	(31)	(3)	(99)	(89)	(10)
Other, net	6	7	(1)	17	18	(1)
Total other income and (deductions)	(28)	(24)	(4)	(82)	(71)	(11)
Income before income taxes	61	67	(6)	299	320	(21)
Income taxes	8	12	4	26	59	33
Net income	$ 53	$ 55	$ (2)	$ 273	$ 261	$ 12

Three Months Ended September 30, 2020 Compared to Three Months Ended September 30, 2019. **Net income** remained relatively consistent primarily due to higher electric and natural gas distribution rates that became effective December 2019, offset by an increase in various expenses.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019. **Net income** increased by $12 million primarily due to higher natural gas and electric distribution rates that became effective December 2019, partially offset by an increase in depreciation and amortization expense.

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

	Three Months Ended September 30, 2020 Increase (Decrease)			Nine Months Ended September 30, 2020 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution	$ 8	$ 3	$ 11	$ 18	$ 38	$ 56
Transmission	3	—	3	(8)	—	(8)
Other	(6)	(2)	(8)	(7)	(6)	(13)
	5	1	6	3	32	35
Regulatory required programs	21	1	22	(57)	(21)	(78)
Total increase (decrease)	$ 26	$ 2	$ 28	$ (54)	$ 11	$ (43)

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

Number of Electric Customers	As of September 30, 2020	As of September 30, 2019
Residential	1,187,498	1,174,188
Small commercial & industrial	114,038	114,301
Large commercial & industrial	12,428	12,296
Public authorities & electric railroads	267	264
Total	1,314,231	1,301,049

Number of Natural Gas Customers	As of September 30, 2020	2019
Residential	644,872	636,030
Small commercial & industrial	38,173	38,129
Large commercial & industrial	6,083	6,005
Total	689,128	680,164

Distribution Revenue increased for the three and nine months ended September 30, 2020, compared to the same period in 2019, primarily due to the impact of higher natural gas and electric distribution rates that became effective in December 2019. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenue. Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered, and the highest daily peak load, which is updated annually in January based on the prior calendar year. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. Transmission revenue remained relatively consistent for the three months ended September 30, 2020, compared to the same period in 2019, and decreased for the nine months ended September 30, 2020, compared to the same period in 2019, primarily due to the settlement agreement of ongoing transmission-related income tax regulatory liabilities. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other revenue includes revenue related to mutual assistance, administrative charges, off-system sales, and late payment charges. Other revenues decreased for the three and nine months ended September 30, 2020, compared to the same period in 2019, as BGE temporarily suspended customer disconnections for non-payment and temporarily ceased new late fees for all customers and restored service to customers upon request who were disconnected in the last twelve months.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as conservation, demand response, STRIDE, and the POLR mechanism. The riders are designed to provide full and current cost recovery, as well as a return in certain instances. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. Customer choice programs do not impact the volume of deliveries but impact Operating revenues related to supplied electricity and natural gas. Drivers of Operating revenues related to commodity procurement costs and participation in customer choice programs are fully offset by their impact on Purchased power and fuel expense. BGE recovers electricity, natural gas, and procurement costs from customers with a slight mark-up.

See Note 4 — Segment Information of the Combined Notes to the Consolidated Financial Statements for the presentation of BGE's revenue disaggregation.

The increase of $15 million and decrease of $73 million for the three and nine months ended September 30, 2020 compared to the same period in 2019, respectively, in **Purchased power and fuel expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	Three Months Ended September 30, 2020 (Decrease) Increase	Nine Months Ended September 30, 2020 (Decrease) Increase
Labor, other benefits, contracting and materials	$ (5)	$ (3)
Storm-related costs	3	(3)
Pension and non-pension postretirement benefits expense	—	(1)
Credit loss expense[(a)]	1	7
BSC costs	—	4
Other	(5)	(5)
	(6)	(1)
Regulatory required programs	1	(1)
Total decrease	$ (5)	$ (2)

(a) Increased credit loss expense primarily as a result of suspending customer disconnections, offset by the regulatory asset recorded in the third quarter of 2020 related to incremental credit loss expense due to COVID-19. See Note 2 - Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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

	Three Months Ended September 30, 2020 Increase	Nine Months Ended September 30, 2020 Increase
Depreciation and amortization[(a)]	$ 9	$ 30
Regulatory asset amortization	—	1
Regulatory required programs	8	6
Total increase	$ 17	$ 37

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

Interest expense, net for the nine months ended September 30, 2020 and 2019, increased due to the issuance of debt in September 2019 and June 2020.

Effective income tax rates were 13.1% and 17.9% for the three months ended September 30, 2020 and 2019, respectively, and 8.7% and 18.4% for the nine months ended September 30, 2020 and 2019. The change for the nine months ended September 30, 2020 compared to the same period in 2019, is primarily related to the settlement agreement of ongoing transmission-related income tax regulatory liabilities. See Note 2 — Regulatory Matters and Note 9 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations — PHI

PHI's Results of Operations include the results of its three reportable segments, Pepco, DPL, and ACE. PHI also has a business services subsidiary, PHISCO, which provides a variety of support services and the costs are directly charged or allocated to the applicable subsidiaries. Additionally, the results of PHI's corporate operations include interest costs from various financing activities. All material intercompany accounts and transactions have been eliminated in consolidation. See the Results of Operations for Pepco, DPL, and ACE for additional information.

	Three Months Ended September 30,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2020	2019		2020	2019	
PHI	$ 216	$ 189	$ 27	$ 418	$ 412	$ 6
Pepco	118	98	20	227	217	10
DPL	27	33	(6)	91	116	(25)
ACE	75	63	12	106	87	19
Other[(a)]	(4)	(5)	1	(6)	(8)	2

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

Three Months Ended September 30, 2020 Compared to Three Months Ended September 30, 2019. Net Income increased by $27 million primarily due to higher electric distribution rates primarily at DPL, higher transmission rates (net of the impact of the settlement agreement of ongoing transmission-related income tax regulatory liabilities), and decreased expense resulting from an absence of an increase in environmental liabilities, partially offset by an increase in DPL storm costs related to the August 2020 storms.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019. Net Income increased by $6 million primarily due to higher electric distribution rates, higher transmission rates (net of the impact of the settlement agreement of ongoing transmission-related income tax regulatory liabilities), and decreased expense resulting from an absence of an increase in environmental liabilities and an expiration of lease arrangement, partially offset by an increase in depreciation and amortization, an increase in DPL storm costs related to the August 2020 storms, an increase in credit loss expense primarily as a result of suspending customer disconnections offset by the regulatory asset recorded in the third quarter of 2020 related to incremental credit loss expense due to COVID-19, and unfavorable weather conditions in ACE and DPL Delaware's service territories.

Results of Operations — Pepco

	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019	Favorable (Unfavorable) Variance
Operating revenues	$ 611	$ 642	$ (31)	$ 1,650	$ 1,748	$ (98)
Operating expenses						
Purchased power expense	163	181	18	467	513	46
Operating and maintenance	106	135	29	336	364	28
Depreciation and amortization	96	95	(1)	282	281	(1)
Taxes other than income taxes	100	104	4	279	286	7
Total operating expenses	465	515	50	1,364	1,444	80
Operating income	146	127	19	286	304	(18)
Other income and (deductions)						
Interest expense, net	(35)	(33)	(2)	(103)	(100)	(3)
Other, net	10	9	1	28	22	6
Total other income and (deductions)	(25)	(24)	(1)	(75)	(78)	3
Income before income taxes	121	103	18	211	226	(15)
Income taxes	3	5	2	(16)	9	25
Net income	$ 118	$ 98	$ 20	$ 227	$ 217	$ 10

Three Months Ended September 30, 2020 Compared to Three Months Ended September 30, 2019. **Net income** increased by $20 million primarily due to decreased expense resulting from an absence of an increase in environmental liabilities.

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019. **Net income** increased by $10 million primarily due to decreased expense resulting from an absence of an increase in environmental liabilities and an expiration of lease arrangement, partially offset by an increase in depreciation and amortization and an increase in credit loss expense primarily as a result of suspending customer disconnections offset by the regulatory asset recorded in the third quarter of 2020 related to incremental credit loss expense due to COVID-19.

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

	Three Months Ended September 30, 2020 (Decrease) Increase	Nine Months Ended September 30, 2020 Increase (Decrease)
Distribution	$ —	$ 7
Transmission	(4)	(33)
Other	(2)	(2)
	(6)	(28)
Regulatory required programs	(25)	(70)
Total decrease	$ (31)	$ (98)

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

Number of Electric Customers	As of September 30, 2020	2019
Residential	828,578	814,412
Small commercial & industrial	53,813	54,130
Large commercial & industrial	22,485	22,240
Public authorities & electric railroads	167	158
Total	905,043	890,940

Distribution Revenue increased for the nine months ended September 30, 2020 compared to the same period in 2019, due to higher electric distribution rates in Maryland that became effective in August 2019.

Transmission Revenues. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered, and the highest daily peak load, which is updated annually in January based on the prior calendar year. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. Transmission revenues decreased for the three and nine months ended September 30, 2020 compared to the same period in 2019, primarily due to the settlement agreement of ongoing transmission-related income tax regulatory liabilities. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues, and recoveries of other taxes. Other revenue decreased for the three and nine months ended September 30, 2020, compared to the same period in 2019, as Pepco temporarily suspended customer disconnections for non-payment and temporarily ceased new late fees for all customers and restored services to customers upon request who were disconnected in the last twelve months.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, DC PLUG, and SOS procurement and administrative costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries, but impact Operating revenues related to supplied electricity. Drivers of Operating revenues related to commodity and REC procurement costs and participation in customer choice programs are fully offset by their impact on Purchased power expense. Pepco recovers electricity and REC procurement costs from customers with a slight mark-up.

See Note 4 - Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of Pepco's revenue disaggregation.

The decrease of $18 million and $46 million for the three and nine months ended September 30, 2020 compared to the same period 2019, respectively, in **Purchased power expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2020
	Increase (Decrease)	Increase (Decrease)
Labor, other benefits, contracting and materials	$ 4	$ 15
Credit loss expense[a]	(2)	6
Storm-related costs	—	(1)
Pension and non-pension postretirement benefits expense	(2)	(5)
BSC and PHISCO costs	(1)	(4)
Expiration of lease arrangement	(4)	(12)
Change in environmental liabilities	(23)	(23)
Other	1	(3)
	(27)	(27)
Regulatory required programs	(2)	(1)
Total decrease	$ (29)	$ (28)

____

(a) Increased credit loss expense for the nine months ended September 30, 2020 primarily as a result of suspending customer disconnections, offset by the regulatory asset recorded in the third quarter of 2020 related to incremental credit loss expense due to COVID-19. Decreased credit loss expense for the three months ended September 30, 2020 is due to the reversal of credit loss expense when the regulatory asset was recorded. See Note 2 - Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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

	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2020
	Increase (Decrease)	Increase (Decrease)
Depreciation and amortization[a]	$ 4	$ 13
Regulatory asset amortization	(1)	(1)
Regulatory required programs	(2)	(11)
Total increase	$ 1	$ 1

____

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

Effective income tax rates were 2.5% and 4.9% for the three months ended September 30, 2020 and 2019, respectively, and (7.6)% and 4.0% for the nine months ended September 30, 2020 and 2019, respectively. The change is primarily related to the settlement agreement of ongoing transmission-related income tax regulatory liabilities. See Note 2 — Regulatory Matters and Note 9 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates.

Results of Operations — DPL

	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019	Favorable (Unfavorable) Variance
Operating revenues	$ 337	$ 319	$ 18	$ 954	$ 987	$ (33)
Operating expenses						
Purchased power and fuel expense	131	127	(4)	379	399	20
Operating and maintenance	101	80	(21)	272	240	(32)
Depreciation and amortization	48	46	(2)	143	138	(5)
Taxes other than income taxes	16	15	(1)	49	43	(6)
Total operating expenses	296	268	(28)	843	820	(23)
Operating income	41	51	(10)	111	167	(56)
Other income and (deductions)						
Interest expense, net	(15)	(15)	—	(47)	(45)	(2)
Other, net	2	2	—	7	10	(3)
Total other income and (deductions)	(13)	(13)	—	(40)	(35)	(5)
Income before income taxes	28	38	(10)	71	132	(61)
Income taxes	1	5	4	(20)	16	36
Net income	$ 27	$ 33	$ (6)	$ 91	$ 116	$ (25)

***Three Months Ended September 30, 2020 Compared to Three Months Ended September 30, 2019*.** **Net income** decreased by $6 million primarily due to an increase in storm costs related to the August 2020 storms in Delaware, partially offset by higher electric distribution rates.

***Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019*.** **Net income** decreased by $25 million primarily due to an increase in storm costs related to the August 2020 storms in Delaware, an increase in depreciation and amortization, an increase in credit loss expense primarily as a result of suspending customer disconnections offset by the regulatory asset recorded in the third quarter of 2020 related to incremental credit loss expense due to COVID-19, and unfavorable weather conditions in DPL's Delaware service territory, partially offset by higher electric distribution rates.

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

	Three Months Ended September 30, 2020 Increase (Decrease)			Nine Months Ended September 30, 2020 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$ (2)	$ 2	$ —	$ (6)	$ 1	$ (5)
Volume	3	(1)	2	2	(4)	(2)
Distribution	4	2	6	7	5	12
Transmission	2	—	2	(21)	—	(21)
Other	3	—	3	2	(1)	1
	10	3	13	(16)	1	(15)
Regulatory required programs	5	—	5	(17)	(1)	(18)
Total increase (decrease)	$ 15	$ 3	$ 18	$ (33)	$ —	$ (33)

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

Weather. The demand for electricity and natural gas in Delaware is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the nine months ended September 30, 2020 compared to the same period in 2019, Operating revenues related to weather decreased due to the impact of unfavorable weather conditions in DPL's Delaware service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in DPL's Delaware electric service territory and a 30-year period in DPL's Delaware natural gas service territory. The changes in heating and cooling degree days in DPL's Delaware service territory for the three and nine months ended September 30, 2020 compared to same period in 2019 and normal weather consisted of the following:

Delaware Electric Service Territory				% Change	
Three Months Ended September 30,	2020	2019	Normal	2020 vs. 2019	2020 vs. Normal
Heating Degree-Days	55	6	32	816.7 %	71.9 %
Cooling Degree-Days	961	1,043	876	(7.9)%	9.7 %
				% Change	
Nine Months Ended September 30,	2020	2019	Normal	2020 vs. 2019	2020 vs. Normal
Heating Degree-Days	2,664	2,828	3,012	(5.8)%	(11.6)%
Cooling Degree-Days	1,260	1,429	1,210	(11.8)%	4.1 %

Delaware Natural Gas Service Territory				% Change	
Three Months Ended September 30,	2020	2019	Normal	2020 vs. 2019	2020 vs. Normal
Heating Degree-Days	55	6	39	816.7 %	41.0 %
				% Change	
Nine Months Ended September 30,	2020	2019	Normal	2020 vs. 2019	2020 vs. Normal
Heating Degree-Days	2,664	2,828	3,023	(5.8)%	(11.9)%

Volume, exclusive of the effects of weather, remained relatively consistent for the three and nine months ended September 30, 2020 compared to the same period in 2019.

Electric Retail Deliveries to Delaware Customers (in GWhs)	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	% Change	Weather - Normal % Change[(b)]	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019	% Change	Weather - Normal % Change[(b)]
Residential	1,028	947	8.6 %	12.3 %	2,474	2,450	1.0 %	5.4 %
Small commercial & industrial	373	387	(3.6)%	(1.9)%	943	1,013	(6.9)%	(4.7) %
Large commercial & industrial	775	924	(16.1)%	(15.4)%	2,408	2,600	(7.4)%	(6.5) %
Public authorities & electric railroads	6	8	(25.0)%	(24.1)%	23	25	(8.0)%	(5.8) %
Total electric retail deliveries[(a)]	2,182	2,266	(3.7)%	(1.8)%	5,848	6,088	(3.9)%	(1.4) %

	As of September 30,	
Number of Total Electric Customers (Maryland and Delaware)	2020	2019
Residential	471,875	466,972
Small commercial & industrial	62,291	61,657
Large commercial & industrial	1,234	1,418
Public authorities & electric railroads	610	616
Total	536,010	530,663

(a) Reflects delivery volumes from customers purchasing electricity directly from DPL and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.
(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 20-year average.

Natural Gas Retail Deliveries to Delaware Customers (in mmcf)	Three Months Ended September 30, 2020	2019	% Change	Weather - Normal % Change[(b)]	Nine Months Ended September 30, 2020	2019	% Change	Weather - Normal % Change[(b)]
Residential	441	403	9.4 %	(11.1)%	5,256	5,751	(8.6)%	(3.5) %
Small commercial & industrial	339	386	(12.2)%	(20.8)%	2,567	2,972	(13.6)%	(9.1) %
Large commercial & industrial	402	407	(1.2)%	(1.2)%	1,265	1,372	(7.8)%	(7.8) %
Transportation	1,231	1,212	1.6 %	— %	4,811	4,905	(1.9)%	(0.7) %
Total natural gas deliveries[(a)]	2,413	2,408	0.2 %	(5.7)%	13,899	15,000	(7.3)%	(4.1) %

Number of Delaware Natural Gas Customers	As of September 30, 2020	2019
Residential	126,659	124,944
Small commercial & industrial	9,885	9,885
Large commercial & industrial	17	18
Transportation	160	158
Total	136,721	135,005

(a) Reflects delivery volumes from customers purchasing natural gas directly from DPL and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges.
(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 30-year average.

Distribution Revenue increased for the three and nine months ended September 30, 2020 compared to the same period in 2019 primarily due to higher electric distribution rates in Maryland that became effective in July 2020 and the Distribution System Improvement Charge (DSIC) fully implemented in the first quarter of 2020.

Transmission Revenues. Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered, and the highest daily peak load, which is updated annually in January based on the prior calendar years. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. Transmission revenue decreased for the nine months ended September 30, 2020 compared to the same period in 2019 primarily due to the settlement agreement of ongoing transmission-related income tax regulatory liabilities. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, DE Renewable Portfolio Standards, SOS procurement and administrative costs, and GCR costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries, but impact Operating revenues related to supplied electricity. Drivers of Operating revenues related to commodity and REC procurement costs and participation in customer choice programs are fully offset by their impact on Purchased power expense. DPL recovers electricity and REC procurement costs from customers with a slight mark-up and natural gas costs from customers without mark-up.

See Note 4 - Segment Information for the Combined Notes to Consolidated Financial Statements for the presentation of DPL's revenue disaggregation.

The increase of $4 million and decrease of $20 million for the three and nine months ended September 30, 2020, respectively, compared to the same period in 2019, in **Purchased power and fuel expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2020
	Increase (Decrease)	Increase (Decrease)
Labor, other benefits, contracting and materials	$ 1	$ 8
Credit loss expense[a]	2	9
Storm-related costs	17	20
Pension and non-pension postretirement benefits expense	(1)	(3)
BSC and PHISCO costs	(1)	(3)
Other	—	(2)
	18	29
Regulatory required programs	3	3
Total increase	$ 21	$ 32

(a) Increased credit loss expense primarily as a result of suspending customer disconnections, offset by the regulatory asset recorded in the third quarter of 2020 related to incremental credit loss expense due to COVID-19. See Note 2 - Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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

	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2020
	Increase (Decrease)	Increase (Decrease)
Depreciation and amortization[a]	$ 2	$ 7
Regulatory required programs	—	(2)
Total increase	$ 2	$ 5

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

Effective income tax rates were 3.6% and 13.2% for the three months ended September 30, 2020 and 2019, respectively, and (28.2)% and 12.1% for the nine months ended September 30, 2020 and 2019, respectively. The decrease for the nine months ended September 30, 2020 is primarily related to the settlement agreement of ongoing transmission-related income tax regulatory liabilities. See Note 2 — Regulatory Matters and Note 9 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates.

Results of Operations — ACE

	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019	Favorable (Unfavorable) Variance
Operating revenues	$ 420	$ 419	$ 1	$ 952	$ 966	$ (14)
Operating expenses						
Purchased power expense	211	210	(1)	469	479	10
Operating and maintenance	77	86	9	238	241	3
Depreciation and amortization	48	43	(5)	134	114	(20)
Taxes other than income taxes	2	1	(1)	6	4	(2)
Total operating expenses	338	340	2	847	838	(9)
Gain on sale of assets	—	—	—	2	—	2
Operating income	82	79	3	107	128	(21)
Other income and (deductions)						
Interest expense, net	(15)	(15)	—	(45)	(44)	(1)
Other, net	1	1	—	5	5	—
Total other income and (deductions)	(14)	(14)	—	(40)	(39)	(1)
Income before income taxes	68	65	3	67	89	(22)
Income taxes	(7)	2	9	(39)	2	41
Net income	$ 75	$ 63	$ 12	$ 106	$ 87	$ 19

Three Months Ended September 30, 2020 Compared to Three Months Ended September 30, 2019. **Net income** increased by $12 million primarily due to an increase in transmission rates (net of the impact of the settlement agreement of ongoing transmission-related income tax regulatory liabilities).

Nine Months Ended September 30, 2020 Compared to Nine Months Ended September 30, 2019. **Net income** increased by $19 million primarily due to higher electric distribution rates and an increase in transmission rates (net of the impact of the settlement agreement of ongoing transmission-related income tax regulatory liabilities), partially offset by an increase in depreciation and amortization, unfavorable weather conditions in ACE's service territory, and lower commercial and industrial usage.

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

	Three Months Ended September 30, 2020 (Decrease) Increase	Nine Months Ended September 30, 2020 (Decrease) Increase
Weather	$ (1)	$ (5)
Volume	1	(5)
Distribution	—	20
Transmission	(1)	(19)
Other	4	1
	3	(8)
Regulatory required programs	(2)	(6)
Total increase (decrease)	$ 1	$ (14)

Weather. The demand for electricity is affected by weather conditions. With respect to the electric business, very warm weather in summer months and very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity. Conversely, mild weather reduces demand. There was a decrease related to weather for the three and nine months ended September 30, 2020 compared to same period in 2019 due to the impact of unfavorable weather conditions in ACE's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in ACE's service territory. The changes in heating and cooling degree days in ACE's service territory for the three and nine months ended September 30, 2020 compared to same period in 2019 consisted of the following:

Heating and Cooling Degree-Days Three Months Ended September 30,	2020	2019	Normal	% Change 2020 vs. 2019	% Change 2020 vs. Normal
Heating Degree-Days	58	13	36	346.2 %	61.1 %
Cooling Degree-Days	989	980	839	0.9 %	17.9 %

Nine Months Ended September 30,	2020	2019	Normal	% Change 2020 vs. 2019	% Change 2020 vs. Normal
Heating Degree-Days	2,618	2,899	3,069	(9.7)%	(14.7)%
Cooling Degree-Days	1,300	1,330	1,143	(2.3)%	13.7 %

Volume, exclusive of the effects of weather, increased for the three months ended September 30, 2020 and decreased for the nine months ended September 30, 2020 compared to the same period in 2019, primarily due to lower commercial and industrial usage.

Electric Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019	% Change	Weather - Normal % Change[(b)]	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019	% Change	Weather - Normal % Change[(b)]
Residential	1,533	1,470	4.3 %	5.4 %	3,193	3,182	0.3 %	3.1 %
Small commercial & industrial	397	431	(7.9)%	(9.1) %	967	1,055	(8.3)%	(7.5)%
Large commercial & industrial	851	938	(9.3)%	(9.6) %	2,287	2,600	(12.0)%	(11.6)%
Public authorities & electric railroads	9	10	(10.0)%	(5.8) %	33	34	(2.9)%	(2.3)%
Total electric retail deliveries[(a)]	2,790	2,849	(2.1)%	(1.9) %	6,480	6,871	(5.7)%	(4.2)%

Number of Electric Customers	As of September 30, 2020	As of September 30, 2019
Residential	497,222	493,720
Small commercial & industrial	61,521	61,376
Large commercial & industrial	3,305	3,418
Public authorities & electric railroads	694	676
Total	562,742	559,190

____

(a) Reflects delivery volumes from customers purchasing electricity directly from ACE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.
(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 20-year average.

Distribution Revenue increased for the nine months ended September 30, 2020 compared to the same period in 2019 primarily due to higher electric distribution rates that became effective in April 2019 and April 2020.

Transmission Revenues. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered, and the highest daily peak load, which is updated annually in January based on the prior calendar year. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. Transmission revenue decreased for the three and nine months ended September 30, 2020 compared to the same period in 2019, primarily due to settlement agreement for ongoing transmission-related income tax regulatory liabilities. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, Societal Benefits Charge, Transition Bonds, and BGS procurement and administrative costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries, but impact Operating revenues related to supplied electricity. Drivers of Operating revenues related to commodity, REC and ZEC procurement costs, and participation in customer choice programs are fully offset by their impact on Purchased power expense. ACE recovers electricity, REC, and ZEC procurement costs from customers without mark-up.

See Note 4 - Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ACE's revenue disaggregation.

The increase of $1 million for the three months ended September 30, 2020 and decrease of $10 million for the nine months ended September 30, 2020 compared to the same period in 2019, in **Purchased power expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2020
	(Decrease) Increase	Increase (Decrease)
Labor, other benefits, contracting and materials	$ (2)	$ 7
Pension and non-pension postretirement benefits expense	—	(1)
Storm-related costs	1	(1)
BSC and PHISCO costs	(1)	(2)
Other	(2)	(6)
	(4)	(3)
Regulatory required programs[(a)]	(5)	—
Total decrease	$ (9)	$ (3)

(a) ACE is allowed to recover from or refund to customers the difference between its annual credit loss expense and the amounts collected in rates annually through the Societal Benefits Charge. During the three months ended September 30, 2020, ACE recorded a net decrease in credit losses account due to the timing of regulatory cost recovery. An equal and offsetting amount has been recognized in Operating revenues for the period presented.

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

	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2020
	Increase (Decrease)	Increase (Decrease)
Depreciation and amortization[(a)]	$ 3	$ 14
Regulatory asset amortization	(1)	(2)
Regulatory required programs	3	8
Total increase	$ 5	$ 20

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

Gain on sale of assets for the nine months ended September 30, 2020 compared to the same period in 2019 increased due to the sale of land in February 2020.

Effective income tax rates were (10.3)% and 3.1% for the three months ended September 30, 2020 and 2019, respectively, (58.2)% and 2.2% for the nine months ended September 30, 2020 and 2019, respectively. The change is primarily related to the settlement agreement of ongoing transmission-related income tax regulatory liabilities. See Note 2 — Regulatory Matters and Note 9 — Income Taxes of the Combined Notes to Consolidated

Financial Statements for additional information regarding the components of the change in effective income tax rates.

Liquidity and Capital Resources

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

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations, the sale of certain receivables, as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each of the Registrants annually evaluates its financing plan, dividend practices, and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and OPEB obligations, and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet its needs and fund growth including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, the Registrants have access to credit facilities with aggregate bank commitments of $10.6 billion. As a result of disruptions in the commercial paper markets due to COVID-19 in March of 2020, Generation borrowed $1.5 billion on its revolving credit facility to refinance commercial paper. Generation repaid the $1.5 billion borrowed on the revolving credit facility on April 3, 2020 using funds from short-term loans issued in March 2020, cash proceeds from the sale of certain customer accounts receivable, and borrowings from the Exelon intercompany money pool. See Note 5 - Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information on the sale of customer accounts receivable. Exelon Corporate, Generation, and the Utility Registrants continued to issue commercial paper during the third quarter of 2020. See Executive Overview for additional information on COVID-19. The Registrants continue to utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the "Credit Matters" section below for additional information. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations, and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, the Utility Registrants operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' debt and credit agreements.

Despite disruptions in the financial markets due to COVID-19, the Registrants have been able to fund their liquidity needs to date. As of December 31, 2019, Exelon had approximately $4.0 billion of long-term debt that matures in 2020, excluding project financings and floating rate long-term debt. Of this, as of September 30, 2020, Exelon has redeemed or refinanced approximately $3.4 billion that is maturing in 2020. The remaining amount of $0.6 billion on Exelon's and Generation's Consolidated Balance Sheet was redeemed on October 2, 2020. To date in 2020, the Registrants have been able to execute their expected debt issuances and have issued long-term debt of $5.3 billion, of which $4.1 billion was issued in the period of April to October of 2020. The Registrants accelerated the timing of a number of planned debt issuances resulting in the $4.1 billion issued in the period of April to October of 2020 and the Registrants have now completed their planned long-term debt issuances for the 2020 year.

NRC Minimum Funding Requirements (Exelon and Generation)

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are based upon the assumption that decommissioning activities will commence after the end of the current licensed life of each unit. If a unit fails the NRC minimum funding test, then the plant's owners or parent companies would be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional cash contributions to the NDT fund to ensure sufficient funds are available. See Note 7 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional information.

If a nuclear plant were to early retire there is a risk that it will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT funds could appreciate in value. A shortfall could require that Generation address the shortfall by, among other things, obtaining a parental guarantee for Generation's share of the funding assurance. However, the amount of any guarantees or other assurance will ultimately depend on the decommissioning approach, the associated level of costs, and the NDT fund investment performance going forward. Within two years after shutting down a plant, Generation must submit a PSDAR to the NRC that includes the planned option for decommissioning the site. Upon retirement, Dresden will have adequate funding assurance, however, due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT fund investments could appreciate in value, Byron may no longer meet the NRC minimum funding requirements and, as a result, the NRC may require additional financial assurance including possibly a parental guarantee from Exelon. Considering the different approaches to decommissioning available to Generation, the most likely estimates currently anticipated could require financial assurance for radiological decommissioning at Byron of up to $275 million.

Upon issuance of any required financial guarantees, each site would be able to utilize the respective NDT funds for radiological decommissioning costs, which represent the majority of the total expected decommissioning costs. However, under the regulations, the NRC must approve an exemption in order for Generation to utilize the NDT funds to pay for non-radiological decommissioning costs (i.e. spent fuel management and site restoration costs, if applicable). If a unit does not receive this exemption, those costs would be borne by Generation without reimbursement from or access to the NDT funds. Accordingly, based on current projections of the most likely decommissioning approach, it is expected that Dresden would not require supplemental cash from Generation, but some portion of the Byron spent fuel management costs would need to be funded through supplemental cash from Generation. While the ultimate amounts may vary and could be offset by reimbursement of certain spent fuel management costs under the DOE settlement agreement, decommissioning for Byron may require supplemental cash from Generation of up to $180 million, net of taxes, over a period of 10 years after permanent shutdown.

As of September 30, 2020, Exelon would not be required to post a parental guarantee for TMI Unit 1 under the SAFSTOR scenario which is the planned decommissioning option as described in the TMI Unit 1 PSDAR filed by Generation with the NRC on April 5, 2019. On October 16, 2019, the NRC granted Generation's exemption request to use the TMI Unit 1 NDT funds for spent fuel management costs. An additional exemption request would be required to allow the funds to be spent on site restoration costs, which are not expected to be incurred in the near term.

Project Financing (Exelon and Generation)

Project financing is used to help mitigate risk of specific generating assets. Project financing is based upon a nonrecourse financial structure, in which project debt is paid back from the cash generated by the specific asset or portfolio of assets. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against Exelon or Generation in the event of a default. If a specific project financing entity does not maintain compliance with its specific debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other project-related borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, or restructured, the lenders or security holders would generally have rights to foreclose against the project-specific assets and related collateral. The potential requirement to satisfy its associated debt or other borrowings earlier than otherwise anticipated could lead to impairments due to a higher likelihood of disposing of the respective project-specific assets significantly before the end of their useful lives. Additionally, project finance has credit facilities. See Note 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on nonrecourse debt. Refer to Note 16 — Debt and Credit Agreements of the Exelon 2019 Form 10-K for additional information on credit facilities.

Cash Flows from Operating Activities (All Registrants)

General

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

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

See Note 3 — Regulatory Matters and Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2019 Form 10-K for additional information of regulatory and legal proceedings and proposed legislation.

The following table provides a summary of the change in cash flows from operating activities for the nine months ended September 30, 2020 and 2019 by Registrant:

(Decrease) increase in cash flows from operating activities	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net income	$ (701)	$ (299)	$ (240)	$ (93)	$ 12	$ 6	$ 10	$ (25)	$ 19
Adjustments to reconcile net income to cash:									
Non-cash operating activities	562	264	353	—	25	(91)	(84)	13	(9)
Pension and non-pension postretirement benefit contributions	(203)	(84)	(74)	8	(29)	(20)	2	—	(3)
Income taxes	(174)	(215)	(47)	63	89	(3)	12	(23)	(1)
Changes in working capital and other noncurrent assets and liabilities	(1,415)	(1,564)	(20)	119	(39)	48	104	(5)	(54)
Option premiums (paid) received, net	(144)	(144)	—	—	—	—	—	—	—
Collateral received (posted), net	898	932	(40)	—	5	—	—	—	—
(Decrease) increase in cash flows from operating activities	$ (1,177)	$ (1,110)	$ (68)	$ 97	$ 63	$ (60)	$ 44	$ (40)	$ (48)

Changes in the Registrants' cash flows from operations were generally consistent with changes in each Registrant’s respective results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. In addition, significant operating cash flow impacts for the Registrants for the nine months ended September 30, 2020 and 2019 were as follows:

- See Note 17 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements and the Registrants’ Consolidated Statement of Cash Flows for additional information on **non-cash operating activity**.
- See Note 9 — Income Taxes of the Combined Notes to Consolidated Financial Statements and the Registrants' Consolidated Statement of Cash Flows for additional information on **income taxes**.
- Depending upon whether Generation is in a net mark-to-market liability or asset position, **collateral** may be required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on an exchange or in the OTC markets.
- During 2020, Exelon and Generation derecognized approximately $1.2 billion of accounts receivable. See Note 5 — Accounts Receivable for additional information on the sales of customer **accounts receivable**.

Cash Flows from Investing Activities (All Registrants)

The following table provides a summary of the change in cash flows from investing activities for the nine months ended September 30, 2020 and 2019 by Registrant:

Increase (decrease) in cash flows from investing activities	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Capital expenditures	$ (347)	$ 70	$ (170)	$ (149)	$ 4	$ (66)	$ (57)	$ (33)	$ 19
Proceeds from NDT fund sales, net	(74)	(74)	—	—	—	—	—	—	—
Proceeds from sales of assets and businesses	29	29	—	—	—	—	—	—	—
Changes in intercompany money pool	—	—	—	68	—	—	(117)	—	—
Collection of DPP	2,518	2,518	—	—	—	—	—	—	—
Other investing activities	(23)	11	(25)	(3)	(4)	—	(5)	(4)	5
Increase (decrease) in cash flows from investing activities	$ 2,103	$ 2,554	$ (195)	$ (84)	$ —	$ (66)	$ (179)	$ (37)	$ 24

Significant investing cash flow impacts for the Registrants for nine months ended September 30, 2020 and 2019 were as follows:

- Variances in **capital expenditures** are primarily due to the timing of cash expenditures for capital projects. Refer below for additional information on projected capital expenditure spending.
- Changes in **intercompany money pool** are driven by short-term borrowing needs. Refer to more information regarding the intercompany money pool below.

Capital Expenditure Spending

As of September 30, 2020, the most recent estimates of capital expenditures for plant additions and improvements for 2020 are as follows:

(In millions)	Transmission	Distribution	Gas	Total
Exelon	N/A	N/A	N/A	$ 8,075
Generation	N/A	N/A	N/A	1,500
ComEd	425	1,900	N/A	2,325
PECO	100	800	300	1,200
BGE	275	550	475	1,300
PHI	425	1,100	100	1,625
Pepco	150	650	N/A	800
DPL	100	250	100	450
ACE	175	200	N/A	375

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

Cash Flows from Financing Activities (All Registrants)

The following table provides a summary of the change in cash flows from financing activities for the nine months ended September 30, 2020 and 2019 by Registrant:

Increase (decrease) in cash flows from financing activities	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Changes in short-term borrowings, net	$ (494)	$ 220	$ (376)	$ —	$ (41)	$ (161)	$ (54)	$ (113)	$ 6
Long-term debt, net	666	(1,053)	400	25	—	202	156	99	(52)
Changes in intercompany money pool	—	100	—	—	—	(1)	—	—	117
Dividends paid on common stock	(64)	—	6	13	(17)	—	(1)	6	(11)
Distributions to member	—	(732)	—	—	—	(22)	—	—	—
Contributions from parent/member	—	64	301	74	180	210	133	112	(38)
Other financing activities	(73)	(11)	(4)	2	(1)	(5)	(3)	(1)	—
Increase (decrease) in cash flows from financing activities	$ 35	$ (1,412)	$ 327	$ 114	$ 121	$ 223	$ 231	$ 103	$ 22

Significant financing cash flow impacts for the Registrants for the nine months ended September 30, 2020 and 2019 were as follows:

- **Changes in short-term borrowings, net**, is driven by repayments on and issuances of notes due in less than 365 days. Refer to 12 — Debt and Credit Agreements of the Consolidated Financial Statements for additional information on short-term borrowings.
- **Long-term debt, net**, varies due to debt issuances and redemptions each year. Refer to 12 — Debt and Credit Agreements of the Consolidated Financial Statements for additional information on debt issuances. Refer to debt redemptions tables below for more information.
- **Changes in intercompany money pool** are driven by short-term borrowing needs. Refer to more information regarding the intercompany money pool below.
- Exelon’s ability to pay **dividends** on its common stock depends on the receipt of dividends paid by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. See Note 14 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2019 Form 10-K for additional information on dividend restrictions. See below for quarterly dividends declared.
- For the nine months ended September 30, 2020, other financing activities primarily consists of debt issuance costs. See Note 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants’ debt issuances.

Debt

See Note 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants’ debt issuances.

During the nine months ended September 30, 2020, the following long-term debt was retired and/or redeemed:

Company[(a)]	Type	Interest Rate	Maturity	Amount
Exelon	Notes	2.85 %	June 15, 2020	$ 900
Exelon	Long-Term Software License Agreement	3.95 %	May 1, 2024	24
Generation	Senior Notes	2.95 %	January 15, 2020	1,000
Generation	Senior Notes	4.00 %	October 1, 2020	550
Generation	Tax-Exempt Bonds	2.50% - 2.70%	December 1, 2025 - June 1, 2036	412
Generation	ExGen Renewables IV Nonrecourse Debt[(b)]	3mL +3%	November 30, 2024	87
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	13
Generation	Renewable Power Generation 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	2
Generation	Energy Efficiency Project Financing	4.12 %	November 30, 2020	1
ComEd	First Mortgage Bonds	4.00 %	August 1, 2020	500
DPL	Tax-Exempt Bonds	5.40 %	February 1, 2031	78
ACE	Tax-Exempt First Mortgage Bonds	4.88 %	June 1, 2029	23
ACE	Transition Bonds	5.55 %	October 20, 2023	14

____

(a) On October 2, 2020, Generation redeemed $550 million of 5.15% senior notes due December 1, 2020. The senior notes are legacy Constellation mirror debt that were previously held at Exelon and Generation. As part of the 2012 Constellation merger, Exelon and Generation assumed intercompany loan agreements that mirrored the terms and amounts of external obligations held by Exelon, resulting in intercompany notes payable at Generation.
(b) See Note 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of nonrecourse debt.

Dividends

Quarterly dividends declared by the Exelon Board of Directors during the nine months ended September 30, 2020 and for the fourth quarter of 2020 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share[(a)]
First Quarter 2020	January 28, 2020	February 20, 2020	March 10, 2020	$ 0.3825
Second Quarter 2020	April 28, 2020	May 15, 2020	June 10, 2020	$ 0.3825
Third Quarter 2020	July 28, 2020	August 14, 2020	September 10, 2020	$ 0.3825
Fourth Quarter 2020	November 2, 2020	November 16, 2020	December 10, 2020	$ 0.3825

____

(a) Exelon's Board of Directors approved an updated dividend policy providing an increase of 5% each year for the period covering 2018 through 2020.

Credit Matters (All Registrants)

The Registrants fund liquidity needs for capital investment, working capital, energy hedging, and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets, and large, diversified credit facilities. The credit facilities include $10.6 billion in aggregate total commitments of which $8.5 billion was available to support additional commercial paper as of September 30, 2020, and of which no financial institution has more than 7% of the aggregate commitments for the Registrants. The Registrants had access to the commercial paper markets and had availability under their revolving credit facilities during the third quarter of 2020 to fund their short-term liquidity needs. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels, and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising, and merger activity. See PART I.

ITEM 1A. RISK FACTORS of the Exelon 2019 Form 10-K for additional information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operating activities, access to credit markets, and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of September 30, 2020, it would have been required to provide incremental collateral of $1.3 billion to meet collateral obligations for derivatives, non-derivatives, normal purchases and normal sales contracts, and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within the $4.9 billion of available credit capacity of its revolver.

The following table presents the incremental collateral that each Utility Registrant would have been required to provide in the event each Utility Registrant lost its investment grade credit rating at September 30, 2020 and available credit facility capacity prior to any incremental collateral at September 30, 2020:

	PJM Credit Policy Collateral	Other Incremental Collateral Required[(a)]	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 12	$ —	$ 857
PECO	—	22	600
BGE	11	31	600
Pepco	11	—	299
DPL	4	10	300
ACE	—	—	300

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

Exelon Credit Facilities

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

See Note 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' short-term borrowing activity. See Note 16 — Debt and Credit Agreements of the Exelon 2019 Form 10-K for additional information on the Registrants' credit facilities.

Security Ratings

The Registrants' access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants' borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant's securities could increase fees and interest charges under that Registrant's credit agreements.

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

The credit ratings for Exelon Corporate, Generation, PECO, BGE, PHI, Pepco, DPL, and ACE did not change for the nine months ended September 30, 2020. On July 21, 2020, S&P lowered ComEd's long-term issuer credit rating from 'A-' to a 'BBB+'. S&P also affirmed the current 'A' rating on ComEd's senior secured debt and 'A-2' short-term rating, which influences long and short-term borrowing cost.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, both Exelon and PHI operate an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of September 30, 2020, are presented in the following table:

Exelon Intercompany Money Pool	During the Three Months Ended September 30, 2020		As of September 30, 2020
Contributed (Borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Exelon Corporate	$ 871	$ —	$ 333
Generation	—	(527)	—
PECO	35	—	—
BSC	—	(494)	(372)
PHI Corporate	—	(22)	(21)
PCI	60	—	60

PHI Intercompany Money Pool	During the Three Months Ended September 30, 2020		As of September 30, 2020
Contributed (Borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Pepco	$ 123	$ (57)	$ 117
DPL	61	—	—
ACE	—	(129)	(117)

Shelf Registration Statements

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

Table of Contents

Regulatory Authorizations

ComEd, PECO, BGE, Pepco, DPL, and ACE are required to obtain short-term and long-term financing authority from Federal and State Commissions as follows:

	As of September 30, 2020					
	Short-term Financing Authority[(a)]			Remaining Long-term Financing Authority[(a)]		
	Commission	Expiration Date	Amount	Commission	Expiration Date	Amount
ComEd	FERC	December 31, 2021	$ 2,500	ICC	February 1, 2023	$ 893
PECO	FERC	December 31, 2021	1,500	PAPUC	December 31, 2021	1,225
BGE	FERC	December 31, 2021	700	MDPSC	N/A	1,100
Pepco	FERC	December 31, 2021	500	MDPSC / DCPSC	December 31, 2022	900
DPL	FERC	December 31, 2021	500	MDPSC / DPSC	December 31, 2022	375
ACE[(b)]	NJBPU	December 31, 2021	350	NJBPU	December 31, 2020	77

(a) Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.
(b) On August 12, 2020, ACE filed an application for $600 million in new long-term debt financing authority from the NJBPU and expects approval before the end of the year.

Contractual Obligations and Off-Balance Sheet Arrangements

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments triggered by future events. See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in the Exelon 2019 Form 10-K.

Generation, ComEd, PECO, BGE, Pepco, DPL, and ACE have obligations related to contracts for the purchase of power and fuel supplies, and ComEd and PECO have obligations related to their financing trusts. The power and fuel purchase contracts and the financing trusts have been considered for consolidation in the Registrants' respective financial statements pursuant to the authoritative guidance for VIEs. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements in the Exelon 2019 Form 10-K for additional information.

For an in-depth discussion of the Registrants' contractual obligations and off-balance sheet arrangements, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations and Off-Balance Sheet Arrangements" in the Exelon 2019 Form 10-K. In addition, see discussion of off-balance sheet arrangement discussed below.

Sales of Customer Accounts Receivable

On April 8, 2020, Generation entered into an accounts receivable financing facility with a number of financial institutions and a commercial paper conduit to sell certain receivables, which expires on April 7, 2021 unless renewed by the mutual consent of the parties in accordance with its terms. The facility allows Generation to obtain financing at lower cost and diversify its sources of liquidity. See Note 5 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities. The following discussion serves as an update to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of Exelon's 2019 Annual Report on Form 10-K incorporated herein by reference.

Commodity Price Risk (All Registrants)

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

Generation

Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of the Utility Registrants' retail load, is sold into the wholesale markets. To reduce commodity price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including swaps, futures, forwards and options, with approved counterparties to hedge anticipated exposures. Generation uses derivative instruments as economic hedges to mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2020 through 2022.

As of September 30, 2020, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 97%-100% and 87%-90% for 2020 and 2021, respectively. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire economic hedge portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on September 30, 2020 market conditions and hedged position would be a decrease in pre-tax net income of approximately $14 million and $99 million, respectively, for 2020 and 2021. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Fuel Procurement

Approximately 60% of Generation's uranium concentrate requirements from 2020 through 2024 are supplied by three suppliers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's financial statements.

Utility Registrants

There have been no significant changes or additions to the Utility Registrants exposures to commodity price risk that were described in ITEM 1A. RISK FACTORS of Exelon's 2019 Annual Report on Form 10-K. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding commodity price risk exposure.

Trading and Non-Trading Marketing Activities

The following table detailing Exelon's, Generation's, and ComEd's trading and non-trading marketing activities are included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon's, Generation's, and ComEd's commodity mark-to-market net asset or liability balance sheet position from December 31, 2019 to September 30, 2020. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings. This table excludes all NPNS contracts and does not segregate proprietary trading activity. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of September 30, 2020 and December 31, 2019.

	Exelon	Generation	ComEd
Total mark-to-market energy contract net assets (liabilities) at December 31, 2019[(a)]	$ 567	$ 868	$ (301)
Total change in fair value during 2020 of contracts recorded in results of operations	14	14	—
Reclassification to realized at settlement of contracts recorded in results of operations	436	436	—
Changes in fair value — recorded through regulatory assets[(b)]	(3)	—	(3)
Changes in allocated collateral	(678)	(678)	—
Net option premium paid	131	131	—
Option premium amortization	(79)	(79)	—
Upfront payments and amortizations[(c)]	(80)	(80)	—
Total mark-to-market energy contract net assets (liabilities) at September 30, 2020[(a)]	$ 308	$ 612	$ (304)

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) For ComEd, the changes in fair value are recorded as a change in regulatory assets. As of September 30, 2020, ComEd recorded a regulatory asset of $304 million related to its mark-to-market derivative liabilities with unaffiliated suppliers. For the nine months ended September 30, 2020, ComEd recorded $26 million of decreases in fair value and an increase for realized losses due to settlements of $23 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.
(c) Includes derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums, and the associated amortizations.

Fair Values

The following tables present maturity and source of fair value for Exelon, Generation, and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities), net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 13 — Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2020	2021	2022	2023	2024	2025 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[(a)(b)]:							
Actively quoted prices (Level 1)	$ 4	$ 69	$ 13	$ 11	$ 11	$ 18	$ 126
Prices provided by external sources (Level 2)	41	60	34	18	(1)	1	153
Prices based on model or other valuation methods (Level 3)[(c)]	17	139	36	14	(11)	(166)	29
Total	$ 62	$ 268	$ 83	$ 43	$ (1)	$ (147)	$ 308

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $251 million at September 30, 2020.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2020	2021	2022	2023	2024	2025 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[(a)(b)]:							
Actively quoted prices (Level 1)	$ 4	$ 69	$ 13	$ 11	$ 11	$ 18	$ 126
Prices provided by external sources (Level 2)	41	60	34	18	(1)	1	153
Prices based on model or other valuation methods (Level 3)	28	167	64	42	16	16	333
Total	$ 73	$ 296	$ 111	$ 71	$ 26	$ 35	$ 612

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $251 million at September 30, 2020.

ComEd

	Maturities Within						
	2020	2021	2022	2023	2024	2025 and Beyond	Total Fair Value
Commodity derivative contracts[(a)]:							
Prices based on model or other valuation methods (Level 3)[(a)]	$ (11)	$ (28)	$ (28)	$ (28)	$ (27)	$ (182)	$ (304)

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

Credit Risk (All Registrants)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that execute derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for detailed discussion of credit risk.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchases and normal sales agreements, and payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of September 30, 2020. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs, and commodity exchanges, which are discussed below.

Rating as of September 30, 2020	Total Exposure Before Credit Collateral	Credit Collateral[a]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 638	$ 27	$ 611	—	$ —
Non-investment grade	4	—	4		
No external ratings					
Internally rated — investment grade	168	1	167		
Internally rated — non-investment grade	110	29	81		
Total	$ 920	$ 57	$ 863	—	$ —

Rating as of September 30, 2020	Maturity of Credit Risk Exposure: Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 568	$ 51	$ 19	$ 638
Non-investment grade	4	—	—	4
No external ratings				
Internally rated — investment grade	123	27	18	168
Internally rated — non-investment grade	89	9	12	110
Total	$ 784	$ 87	$ 49	$ 920

Net Credit Exposure by Type of Counterparty	As of September 30, 2020
Financial institutions	$ 26
Investor-owned utilities, marketers, power producers	650
Energy cooperatives and municipalities	142
Other	45
Total	$ 863

(a) As of September 30, 2020, credit collateral held from counterparties where Generation had credit exposure included $31 million of cash and $26 million of letters of credit.

The Utility Registrants

There have been no significant changes or additions to the Utility Registrants exposures to credit risk that are described in ITEM 1A. RISK FACTORS of Exelon's 2019 Annual Report on Form 10-K.

See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding credit exposure to suppliers.

Credit-Risk-Related Contingent Features (All Registrants)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, natural gas, and other commodities. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding collateral requirements. See Note 14 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the letters of credit supporting the cash collateral.

Generation transacts output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's financial statements. As market prices rise above or fall below contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. To post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See Note 16 — Debt and Credit Agreements of Exelon's 2019 Annual Report on Form 10-K for additional information.

Utility Registrants

As of September 30, 2020, the Utility Registrants were not required to post collateral under their energy and/or natural gas procurement contracts. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Interest Rate and Foreign Exchange Risk (Exelon and Generation)

Exelon and Generation use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. Exelon and Generation may also utilize interest rate swaps to manage their interest rate exposure. A hypothetical 50 basis points increase in the interest rates associated with unhedged variable-rate debt (excluding commercial paper) and fixed-to-floating swaps would result in approximately a $4 million decrease in Exelon pre-tax income for the nine months ended September 30, 2020. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning its nuclear plants. As of September 30, 2020, Generation's NDT funds are reflected at fair value in its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 25 basis points increase in interest rates and 10% decrease in equity prices would result in a $754 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices.

Item 4. Controls and Procedures

During the third quarter of 2020, each of the Registrants' management, including its principal executive officer and principal financial officer, evaluated its disclosure controls and procedures related to the recording, processing, summarizing, and reporting of information in its periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by the Registrants to ensure that (a) material information relating to that Registrant, including its consolidated subsidiaries, is accumulated and made known to Exelon's management, including its principal executive officer and principal financial officer, by other employees of that Registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated, and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of September 30, 2020, the principal executive officer and principal financial officer of each of the Registrants concluded that such Registrant's disclosure controls and procedures were effective to accomplish its objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. There were no changes in internal control over financial reporting during the third quarter of 2020 that materially affected, or are reasonably likely to materially affect, any of the Registrants' internal control over financial reporting, including no changes resulting from COVID-19. See Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Executive Overview for additional information on COVID-19.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see (a) ITEM 3. LEGAL PROCEEDINGS of Exelon's 2019 Form 10-K and (b) Notes 2 — Regulatory Matters and 14 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report. Such descriptions are incorporated herein by these references.

Item 1A. Risk Factors

Risks Related to Exelon

At September 30, 2020, the Registrants' risk factors were consistent with the risk factors described in the Registrants' combined 2019 Form 10-K in ITEM 1A. RISK FACTORS, except for the following risk factors, which were added.

Our Results Could be Negatively Affected by the Impacts of COVID-19 (All Registrants).

The Registrants have taken steps to mitigate the potential risks posed by COVID-19. This is an evolving situation that could lead to extended disruption of economic activity in the Registrants' respective markets. COVID-19 could negatively affect the Registrants' ability to operate their respective generating and transmission and distribution assets, their ability to access capital markets, and results of operations. The Registrants cannot predict the extent of the impacts of COVID-19, which will depend on future developments and which are highly uncertain at this time. See Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Executive Overview for additional information on COVID-19.

Exelon and ComEd have received requests for information related to an SEC investigation into their lobbying activities. The outcome of the investigation 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 criminal or 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 14 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report.

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 ends 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, with $100 million payable within thirty days of the filing of the DPA with the United States District Court for the Northern District of Illinois and an additional $100 million within ninety days of such filing date; (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 14 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report.

Item 4. Mine Safety Disclosures

All Registrants

Not applicable to the Registrants.

Item 5. Other Information

All Registrants

None.

Item 6. Exhibits

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable Registrant and its subsidiaries on a consolidated basis and the relevant Registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
10.1	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)
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)

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2020 filed by the following officers for the following companies:

31-1	— Filed by Christopher M. Crane for Exelon Corporation
31-2	— Filed by Joseph Nigro for Exelon Corporation
31-3	— Filed by Christopher M. Crane for Exelon Generation Company, LLC
31-4	— Filed by Bryan P. Wright for Exelon Generation Company, LLC
31-5	— Filed by Joseph Dominguez for Commonwealth Edison Company
31-6	— Filed by Jeanne M. Jones for Commonwealth Edison Company
31-7	— Filed by Michael A. Innocenzo for PECO Energy Company
31-8	— Filed by Robert J. Stefani for PECO Energy Company
31-9	— Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
31-10	— Filed by David M. Vahos for Baltimore Gas and Electric Company
31-11	— Filed by David M. Velazquez for Pepco Holdings LLC
31-12	— Filed by Phillip S. Barnett for Pepco Holdings LLC
31-13	— Filed by David M. Velazquez for Potomac Electric Power Company
31-14	— Filed by Phillip S. Barnett for Potomac Electric Power Company
31-15	— Filed by David M. Velazquez for Delmarva Power & Light Company
31-16	— Filed by Phillip S. Barnett for Delmarva Power & Light Company
31-17	— Filed by David M. Velazquez for Atlantic City Electric Company
31-18	— Filed by Phillip S. Barnett for Atlantic City Electric Company

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes — Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2020 filed by the following officers for the following companies:

32-1	— Filed by Christopher M. Crane for Exelon Corporation
32-2	— Filed by Joseph Nigro for Exelon Corporation
32-3	— Filed by Christopher M. Crane for Exelon Generation Company, LLC
32-4	— Filed by Bryan P. Wright for Exelon Generation Company, LLC
32-5	— Filed by Joseph Dominguez for Commonwealth Edison Company
32-6	— Filed by Jeanne M. Jones for Commonwealth Edison Company
32-7	— Filed by Michael A. Innocenzo for PECO Energy Company
32-8	— Filed by Robert J. Stefani for PECO Energy Company
32-9	— Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
32-10	— Filed by David M. Vahos for Baltimore Gas and Electric Company
32-11	— Filed by David M. Velazquez for Pepco Holdings LLC
32-12	— Filed by Phillip S. Barnett for Pepco Holdings LLC
32-13	— Filed by David M. Velazquez for Potomac Electric Power Company
32-14	— Filed by Phillip S. Barnett for Potomac Electric Power Company
32-15	— Filed by David M. Velazquez for Delmarva Power & Light Company
32-16	— Filed by Phillip S. Barnett for Delmarva Power & Light Company
32-17	— Filed by David M. Velazquez for Atlantic City Electric Company
32-18	— Filed by Phillip S. Barnett for Atlantic City Electric Company

SIGNATURES

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON CORPORATION

/s/ CHRISTOPHER M. CRANE	/s/ JOSEPH NIGRO
Christopher M. Crane President and Chief Executive Officer (Principal Executive Officer) and Director	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)	

November 3, 2020

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON GENERATION COMPANY, LLC

/s/ CHRISTOPHER M. CRANE	/s/ BRYAN P. WRIGHT
Christopher M. Crane Principal Executive Officer	Bryan P. Wright Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ MATTHEW N. BAUER	
Matthew N. Bauer Vice President and Controller (Principal Accounting Officer)	

November 3, 2020

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

COMMONWEALTH EDISON COMPANY

/s/ JOSEPH DOMINGUEZ	/s/ JEANNE M. JONES
Joseph Dominguez Chief Executive Officer (Principal Executive Officer)	Jeanne M. Jones Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ STEVEN J. CICHOCKI	
Steven J. Cichocki Director, Accounting (Principal Accounting Officer)	

November 3, 2020

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PECO ENERGY COMPANY

/s/ MICHAEL A. INNOCENZO	/s/ ROBERT J. STEFANI
Michael A. Innocenzo President and Chief Executive Officer (Principal Executive Officer)	Robert J. Stefani Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ CAROLINE FULGINITI	
Caroline Fulginiti Director, Accounting (Principal Accounting Officer)	

November 3, 2020

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ CARIM V. KHOUZAMI	/s/ DAVID M. VAHOS
Carim V. Khouzami Chief Executive Officer (Principal Executive Officer)	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)	

November 3, 2020

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PEPCO HOLDINGS LLC

/s/ DAVID M. VELAZQUEZ	/s/ PHILLIP S. BARNETT
David M. Velazquez President and Chief Executive Officer (Principal Executive Officer)	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)	

November 3, 2020

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

POTOMAC ELECTRIC POWER COMPANY

/s/ DAVID M. VELAZQUEZ	/s/ PHILLIP S. BARNETT
David M. Velazquez President and Chief Executive Officer (Principal Executive Officer)	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)	

November 3, 2020

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DELMARVA POWER & LIGHT COMPANY

/s/ DAVID M. VELAZQUEZ	/s/ PHILLIP S. BARNETT
David M. Velazquez President and Chief Executive Officer (Principal Executive Officer)	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)	

November 3, 2020

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

ATLANTIC CITY ELECTRIC COMPANY

/s/ DAVID M. VELAZQUEZ	/s/ PHILLIP S. BARNETT
David M. Velazquez President and Chief Executive Officer (Principal Executive Officer)	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)	

November 3, 2020