EXELON Corp
Form 10-Q
May 02, 2019
UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

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

For the Quarterly Period Ended March 31, 2019
or

o 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
1-16169	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
1-1839	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
1-1910	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)	52-2297449

	701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	
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	New York and Chicago
Series A Junior Debt Subordinated Debentures	EXC22	New York
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

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 x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted 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 x No o

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.

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

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. o

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

The number of shares outstanding of each registrant’s common stock as of March 31, 2019 was:

Exelon Corporation Common Stock, without par value	970,954,879
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,021,331
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000
Pepco Holdings LLC	not applicable
Potomac Electric Power Company Common Stock, $0.01 par value	100
Delmarva Power & Light Company Common Stock, $2.25 par value	1,000
Atlantic City Electric Company Common Stock, $3.00 par value	8,546,017

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

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
PCI	Potomac Capital Investment Corporation and its subsidiaries
Pepco Energy Services or PES	Pepco Energy Services, Inc. and its subsidiaries
PHI Corporate	PHI in its corporate capacity as a holding company
PHISCO	PHI Service Company
SolGen	SolGen, LLC
TMI	Three Mile Island nuclear facility

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
Note "—" of the 2018 Form 10-K	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2018 Annual Report on Form 10-K
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
AMI	Advanced Metering Infrastructure
AOCI	Accumulated Other Comprehensive Income
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
BGS	Basic Generation Service
CAISO	California Independent System Operator
CES	Clean Energy Standard
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
CODM	Chief operating decision maker(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	District of Columbia Public Service Commission
DOE	United States Department of Energy
DOEE	Department of Energy & Environment
DOJ	United States Department of Justice
DPSC	Delaware Public Service Commission
DSP	Default Service Provider
EDF	Electricite de France SA and its subsidiaries
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EmPower	A Maryland demand-side management program for Pepco and DPL
EPA	United States Environmental Protection Agency
EPSA	Electric Power Supply Association
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
GAAP	Generally Accepted Accounting Principles in the United States
GCR	Gas Cost Rate
GHG	Greenhouse Gas
GSA	Generation Supply Adjustment
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	Independent System Operator New England Inc.
ISO-NY	Independent System Operator New York
LIBOR	London Interbank Offered Rate
MATS	U.S. EPA Mercury and Air Toxics Rule
MBR	Market Based Rates Incentive
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
Moody’s	Moody’s Investor Service
MOPR	Minimum Offer Price Rule
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NLRB	National Labor Relations Board
Non-Regulatory Agreements Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NOSA	Nuclear Operating Services Agreement
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
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
Oyster Creek	Oyster Creek Generating Station
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PJM	PJM Interconnection, LLC

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
Rider	Reconcilable Surcharge Recovery Mechanism
RMC	Risk Management Committee
ROE	Return on equity
ROU	Right-of-use
RPS	Renewable Energy Portfolio Standards
RSSA	Reliability Support Services Agreement
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Services
SEC	United States Securities and Exchange Commission
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPP	Southwest Power Pool
TCJA	Tax Cuts and Jobs Act
Transition Bond Charge	Revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees
Transition Bonds	Transition Bonds issued by ACE Funding
Upstream	Natural gas exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council
ZEC	Zero Emission Credit, or Zero Emission Certificate
ZES	Zero Emission Standard

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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. 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 2018 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 22, Commitments and Contingencies; (2) this Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 16, Commitments and Contingencies; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

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

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

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

	Three Months Ended March 31,	
(In millions, except per share data)	2019	2018
Operating revenues		
Competitive businesses revenues	$4,979	$5,113
Rate-regulated utility revenues	4,503	4,570
Revenues from alternative revenue programs	(5)	10
Total operating revenues	9,477	9,693
Operating expenses		
Competitive businesses purchased power and fuel	3,204	3,289
Rate-regulated utility purchased power and fuel	1,349	1,438
Operating and maintenance	2,189	2,384
Depreciation and amortization	1,075	1,091
Taxes other than income	445	446
Total operating expenses	8,262	8,648
Gain on sales of assets and businesses	3	56
Operating income	1,218	1,101
Other income and (deductions)		
Interest expense, net	(397)	(365)
Interest expense to affiliates	(6)	(6)
Other, net	467	(28)
Total other income and (deductions)	64	(399)
Income before income taxes	1,282	702
Income taxes	310	59
Equity in losses of unconsolidated affiliates	(6)	(7)
Net income	966	636
Net income attributable to noncontrolling interests	59	51
Net income attributable to common shareholders	$907	$585
Comprehensive income, net of income taxes		
Net income	$966	$636
Other comprehensive (loss) income, net of income taxes		
Pension and non-pension postretirement benefit plans:		
Prior service benefit reclassified to periodic benefit cost	(16)	(17)
Actuarial loss reclassified to periodic benefit cost	36	61
Pension and non-pension postretirement benefit plan valuation adjustment	(38)	18
Unrealized gain on cash flow hedges	—	8
Unrealized (loss) gain on investments in unconsolidated affiliates	(2)	1
Unrealized gain on foreign currency translation	2	1
Other comprehensive (loss) income	(18)	72
Comprehensive income	948	708
Comprehensive income attributable to noncontrolling interests	58	52
Comprehensive income attributable to common shareholders	$890	$656

Average shares of common stock outstanding:

Basic	971	966
Assumed exercise and/or distributions of stock-based awards	1	2
Diluted[a]	972	968
Earnings per average common share:		
Basic	$0.93	$0.61
Diluted	$0.93	$0.60

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(a) The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was immaterial for the three months ended March 31, 2019 and approximately 5 million for the three months ended March 31, 2018.

See the Combined Notes to Consolidated Financial Statements

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

	Three Months Ended March 31,	
(In millions)	2019	2018
Cash flows from operating activities		
Net income	$966	$636
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	1,460	1,501
Impairment of long-lived assets	7	—
Gain on sales of assets and businesses	—	(56)
Deferred income taxes and amortization of investment tax credits	187	(14)
Net fair value changes related to derivatives	31	259
Net realized and unrealized (gains) losses on NDT funds	(308)	68
Other non-cash operating activities	127	240
Changes in assets and liabilities:		
Accounts receivable	79	133
Inventories	128	167
Accounts payable and accrued expenses	(764)	(451)
Option premiums received (paid), net	6	(27)
Collateral posted, net	(101)	(214)
Income taxes	141	86
Pension and non-pension postretirement benefit contributions	(328)	(331)
Other assets and liabilities	(587)	(495)
Net cash flows provided by operating activities	1,044	1,502
Cash flows from investing activities		
Capital expenditures	(1,873)	(1,880)
Proceeds from NDT fund sales	3,713	1,189
Investment in NDT funds	(3,666)	(1,248)
Proceeds from sales of assets and businesses	8	79
Other investing activities	32	3
Net cash flows used in investing activities	(1,786)	(1,857)
Cash flows from financing activities		
Changes in short-term borrowings	540	726
Proceeds from short-term borrowings with maturities greater than 90 days	—	1
Repayments on short-term borrowings with maturities greater than 90 days	—	(1)
Issuance of long-term debt	402	1,130
Retirement of long-term debt	(352)	(1,241)
Dividends paid on common stock	(352)	(333)
Proceeds from employee stock plans	51	12
Other financing activities	(14)	(30)
Net cash flows provided by financing activities	275	264
Decrease in cash, cash equivalents and restricted cash	(467)	(91)
Cash, cash equivalents and restricted cash at beginning of period	1,781	1,190
Cash, cash equivalents and restricted cash at end of period	$1,314	$1,099

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	$ 880	$ 1,349
Restricted cash and cash equivalents	223	247
Accounts receivable, net		
Customer	4,564	4,607
Other	1,062	1,256
Mark-to-market derivative assets	652	804
Unamortized energy contract assets	49	48
Inventories, net		
Fossil fuel and emission allowances	179	334
Materials and supplies	1,380	1,351
Regulatory assets	1,191	1,222
Assets held for sale	890	904
Other	1,406	1,238
Total current assets	12,476	13,360
Property, plant and equipment, net	77,460	76,707
Deferred debits and other assets		
Regulatory assets	8,222	8,237
Nuclear decommissioning trust funds	12,302	11,661
Investments	620	625
Goodwill	6,677	6,677
Mark-to-market derivative assets	454	452
Unamortized energy contract assets	365	372
Other	3,017	1,575
Total deferred debits and other assets	31,657	29,599
Total assets[(a)]	$ 121,593	$ 119,666

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EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2019	December 31, 2018
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$1,254	$ 714
Long-term debt due within one year	2,508	1,349
Accounts payable	3,327	3,800
Accrued expenses	1,725	2,112
Payables to affiliates	5	5
Regulatory liabilities	522	644
Mark-to-market derivative liabilities	345	475
Unamortized energy contract liabilities	151	149
Renewable energy credit obligation	348	344
Liabilities held for sale	799	777
Other	1,245	1,035
Total current liabilities	12,229	11,404
Long-term debt	32,960	34,075
Long-term debt to financing trusts	390	390
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	11,642	11,330
Asset retirement obligations	9,967	9,679
Pension obligations	3,734	3,988
Non-pension postretirement benefit obligations	1,984	1,928
Spent nuclear fuel obligation	1,178	1,171
Regulatory liabilities	9,781	9,559
Mark-to-market derivative liabilities	434	479
Unamortized energy contract liabilities	432	463
Other	3,158	2,130
Total deferred credits and other liabilities	42,310	40,727
Total liabilities[(a)]	87,889	86,596
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 971 shares and 968 shares outstanding at March 31, 2019 and December 31, 2018, respectively)	19,171	19,116
Treasury stock, at cost (2 shares at March 31, 2019 and December 31, 2018)	(123)	(123)
Retained earnings	15,321	14,766
Accumulated other comprehensive loss, net	(3,012)	(2,995)
Total shareholders' equity	31,357	30,764
Noncontrolling interests	2,347	2,306
Total equity	33,704	33,070
Total liabilities and shareholders' equity	$121,593	$ 119,666

(a) Exelon's consolidated assets include $9,546 million and $9,667 million at March 31, 2019 and December 31, 2018, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $3,572 million and $3,548 million at March 31, 2019 and December 31, 2018, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 2 — Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

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

Three Months Ended March 31, 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 income, net of income taxes	—	—	—	—	(17)	(1)	(18)
Balance, March 31, 2019	972,786	$ 19,171	$ (123)	$ 15,321	$ (3,012)	$ 2,347	$ 33,704

Three Months Ended March 31, 2018

(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, 2017	965,168	$ 18,964	$ (123)	$ 14,081	$ (3,026)	$ 2,291	$ 32,187
Net income	—	—	—	585	—	51	636
Long-term incentive plan activity	1,685	(3)	—	—	—	—	(3)
Employee stock purchase plan issuances	361	12	—	—	—	—	12
Changes in equity of noncontrolling interests	—	—	—	—	—	(9)	(9)
Common stock dividends ($0.35/common share)	—	—	—	(334)	—	—	(334)
Other comprehensive income, net of income taxes	—	—	—	—	71	1	72
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	—	—	14	(10)	—	4
Balance, March 31, 2018	967,214	$ 18,973	$ (123)	$ 14,346	$ (2,965)	$ 2,334	$ 32,565

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

	Three Months Ended March 31,	
(In millions)	2019	2018
Operating revenues		
Operating revenues	$4,979	$5,114
Operating revenues from affiliates	317	398
Total operating revenues	5,296	5,512
Operating expenses		
Purchased power and fuel	3,204	3,289
Purchased power and fuel from affiliates	1	4
Operating and maintenance	1,068	1,178
Operating and maintenance from affiliates	150	161
Depreciation and amortization	405	448
Taxes other than income	135	138
Total operating expenses	4,963	5,218
Gain on sales of assets and businesses	—	53
Operating income	333	347
Other income and (deductions)		
Interest expense, net	(102)	(91)
Interest expense to affiliates	(9)	(10)
Other, net	430	(44)
Total other income and (deductions)	319	(145)
Income before income taxes	652	202
Income taxes	224	9
Equity in losses of unconsolidated affiliates	(6)	(7)
Net income	422	186
Net income attributable to noncontrolling interests	59	50
Net income attributable to membership interest	$363	$136
Comprehensive income, net of income taxes		
Net income	$422	$186
Other comprehensive income (loss), net of income taxes		
Unrealized gain on cash flow hedges	1	7
Unrealized (loss) gain on investments in unconsolidated affiliates	(2)	1
Unrealized gain (loss) on foreign currency translation	2	(1)
Other comprehensive income	1	7
Comprehensive income	423	193
Comprehensive income attributable to noncontrolling interests	58	51
Comprehensive income attributable to membership interest	$365	$142

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

(In millions)	Three Months Ended March 31, 2019	2018
Cash flows from operating activities		
Net income	$422	$186
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	789	858
Impairment of long-lived assets	7	—
Gain on sales of assets and businesses	—	(53)
Deferred income taxes and amortization of investment tax credits	108	(68)
Net fair value changes related to derivatives	33	264
Net realized and unrealized (gains) losses on NDT funds	(308)	68
Other non-cash operating activities	(90)	45
Changes in assets and liabilities:		
Accounts receivable	197	194
Receivables from and payables to affiliates, net	(5)	(15)
Inventories	103	122
Accounts payable and accrued expenses	(411)	(317)
Option premiums received (paid), net	6	(27)
Collateral posted, net	(87)	(214)
Income taxes	146	79
Pension and non-pension postretirement benefit contributions	(141)	(125)
Other assets and liabilities	(187)	(142)
Net cash flows provided by operating activities	582	855
Cash flows from investing activities		
Capital expenditures	(511)	(628)
Proceeds from NDT fund sales	3,713	1,189
Investment in NDT funds	(3,666)	(1,248)
Proceeds from sales of assets and businesses	8	79
Other investing activities	23	(7)
Net cash flows used in investing activities	(433)	(615)
Cash flows from financing activities		
Changes in short-term borrowings	—	165
Proceeds from short-term borrowings with maturities greater than 90 days	—	1
Repayments of short-term borrowings with maturities greater than 90 days	—	(1)
Issuance of long-term debt	2	4
Retirement of long-term debt	(47)	(29)
Changes in Exelon intercompany money pool	(100)	—
Distributions to member	(225)	(188)
Other financing activities	(6)	(9)
Net cash flows used in financing activities	(376)	(57)
(Decrease) increase in cash, cash equivalents and restricted cash	(227)	183
Cash, cash equivalents and restricted cash at beginning of period	903	554
Cash, cash equivalents and restricted cash at end of period	$676	$737

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

(In millions)	March 31, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	$ 537	$ 750
Restricted cash and cash equivalents	139	153
Accounts receivable, net		
Customer	2,800	2,941
Other	367	562
Mark-to-market derivative assets	652	804
Receivables from affiliates	163	173
Unamortized energy contract assets	49	49
Inventories, net		
Fossil fuel and emission allowances	146	251
Materials and supplies	965	963
Assets held for sale	890	904
Other	1,013	883
Total current assets	7,721	8,433
Property, plant and equipment, net	24,034	23,981
Deferred debits and other assets		
Nuclear decommissioning trust funds	12,302	11,661
Investments	404	414
Goodwill	47	47
Mark-to-market derivative assets	454	452
Prepaid pension asset	1,525	1,421
Unamortized energy contract assets	364	371
Deferred income taxes	18	21
Other	1,813	755
Total deferred debits and other assets	16,927	15,142
Total assets[(a)]	$ 48,682	$ 47,556

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

(In millions)	March 31, 2019	December 31, 2018
LIABILITIES AND EQUITY		
Current liabilities		
Long-term debt due within one year	$2,365	$ 906
Accounts payable	1,566	1,847
Accrued expenses	675	898
Payables to affiliates	136	139
Borrowings from Exelon intercompany money pool	—	100
Mark-to-market derivative liabilities	318	449
Unamortized energy contract liabilities	28	31
Renewable energy credit obligation	348	343
Liabilities held for sale	799	777
Other	425	279
Total current liabilities	6,660	5,769
Long-term debt	5,487	6,989
Long-term debt to affiliates	895	898
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,502	3,383
Asset retirement obligations	9,737	9,450
Non-pension postretirement benefit obligations	894	900
Spent nuclear fuel obligation	1,178	1,171
Payables to affiliates	2,870	2,606
Mark-to-market derivative liabilities	219	252
Unamortized energy contract liabilities	16	20
Other	1,528	610
Total deferred credits and other liabilities	19,944	18,392
Total liabilities[(a)]	32,986	32,048
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	9,525	9,518
Undistributed earnings	3,862	3,724
Accumulated other comprehensive loss, net	(36)	(38)
Total member's equity	13,351	13,204
Noncontrolling interests	2,345	2,304
Total equity	15,696	15,508
Total liabilities and equity	$48,682	$ 47,556

(a) Generation's consolidated assets include $9,515 million and $9,634 million at March 31, 2019 and December 31, 2018, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include $3,508 million and $3,480 million at March 31, 2019 and December 31, 2018, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 2 — Variable Interest Entities for additional information.

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

(In millions)	Three Months Ended March 31, 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 (loss), net of income taxes	—	—	2	(1)	1
Balance, March 31, 2019	$9,525	$ 3,862	$ (36)	$ 2,345	$15,696

(In millions)	Three Months Ended March 31, 2018 Member's Equity Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2017	$9,357	$ 4,349	$ (37)	$ 2,290	$15,959
Net income	—	136	—	50	186
Changes in equity of noncontrolling interests	—	—	—	(9)	(9)
Distributions to member	—	(188)	—	—	(188)
Other comprehensive income, net of income taxes	—	—	6	1	7
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	6	(3)	—	3
Balance, March 31, 2018	$9,357	$ 4,303	$ (34)	$ 2,332	$15,958

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

	Three Months Ended March 31,	
(In millions)	2019	2018
Operating revenues		
Electric operating revenues	$1,432	$1,493
Revenues from alternative revenue programs	(28)	5
Operating revenues from affiliates	4	14
Total operating revenues	1,408	1,512
Operating expenses		
Purchased power	388	411
Purchased power from affiliate	97	194
Operating and maintenance	259	253
Operating and maintenance from affiliate	62	60
Depreciation and amortization	251	228
Taxes other than income	78	77
Total operating expenses	1,135	1,223
Gain on sales of assets	3	3
Operating income	276	292
Other income and (deductions)		
Interest expense, net	(84)	(86)
Interest expense to affiliates	(3)	(3)
Other, net	8	8
Total other income and (deductions)	(79)	(81)
Income before income taxes	197	211
Income taxes	40	46
Net income	$157	$165
Comprehensive income	$157	$165

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

(In millions)	Three Months Ended March 31, 2019	2018
Cash flows from operating activities		
Net income	$157	$165
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	251	228
Deferred income taxes and amortization of investment tax credits	34	50
Other non-cash operating activities	56	46
Changes in assets and liabilities:		
Accounts receivable	14	39
Receivables from and payables to affiliates, net	(34)	(19)
Inventories	(3)	5
Accounts payable and accrued expenses	(188)	(158)
Collateral posted, net	(13)	(3)
Income taxes	5	(5)
Pension and non-pension postretirement benefit contributions	(67)	(38)
Other assets and liabilities	(121)	(176)
Net cash flows provided by operating activities	91	134
Cash flows from investing activities		
Capital expenditures	(503)	(531)
Other investing activities	11	8
Net cash flows used in investing activities	(492)	(523)
Cash flows from financing activities		
Changes in short-term borrowings	322	317
Issuance of long-term debt	400	800
Retirement of long-term debt	(300)	(700)
Contributions from parent	63	113
Dividends paid on common stock	(127)	(114)
Other financing activities	(9)	(9)
Net cash flows provided by financing activities	349	407
(Decrease) increase in cash, cash equivalents and restricted cash	(52)	18
Cash, cash equivalents and restricted cash at beginning of period	330	144
Cash, cash equivalents and restricted cash at end of period	$278	$162

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

(In millions)	March 31, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	$ 68	$ 135
Restricted cash	17	29
Accounts receivable, net		
Customer	539	539
Other	336	320
Receivables from affiliates	21	20
Inventories, net	152	148
Regulatory assets	285	293
Other	89	86
Total current assets	1,507	1,570
Property, plant and equipment, net	22,274	22,058
Deferred debits and other assets		
Regulatory assets	1,338	1,307
Investments	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,412	2,217
Prepaid pension asset	1,073	1,035
Other	347	395
Total deferred debits and other assets	7,801	7,585
Total assets	$ 31,582	$ 31,213

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

(In millions)	March 31, 2019	December 31, 2018
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 322	$ —
Long-term debt due within one year	—	300
Accounts payable	491	607
Accrued expenses	229	373
Payables to affiliates	74	119
Customer deposits	112	111
Regulatory liabilities	241	293
Mark-to-market derivative liability	27	26
Other	98	96
Total current liabilities	1,594	1,925
Long-term debt	8,194	7,801
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,870	3,813
Asset retirement obligations	119	118
Non-pension postretirement benefits obligations	196	201
Regulatory liabilities	6,269	6,050
Mark-to-market derivative liability	213	223
Other	582	630
Total deferred credits and other liabilities	11,249	11,035
Total liabilities	21,242	20,966
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	7,385	7,322
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	3,006	2,976
Total shareholders' equity	10,340	10,247
Total liabilities and shareholders' equity	$ 31,582	$ 31,213

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

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

(In millions)	Three Months Ended March 31, 2018 Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
Balance, December 31, 2017	$1,588	$6,822	$ (1,639)	$ 2,771	$ 9,542
Net income	—	—	165	—	165
Appropriation of retained earnings for future dividends	—	—	(165)	165	—
Common stock dividends	—	—	—	(114)	(114)
Contributions from parent	—	113	—	—	113
Balance, March 31, 2018	$1,588	$6,935	$ (1,639)	$ 2,822	$ 9,706

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

	Three Months Ended March 31,	
(In millions)	2019	2018
Operating revenues		
Electric operating revenues	$622	$633
Natural gas operating revenues	280	232
Revenues from alternative revenue programs	(3)	(1)
Operating revenues from affiliates	1	2
Total operating revenues	900	866
Operating expenses		
Purchased power	152	199
Purchased fuel	135	98
Purchased power from affiliate	44	36
Operating and maintenance	187	233
Operating and maintenance from affiliates	38	42
Depreciation and amortization	81	75
Taxes other than income	41	41
Total operating expenses	678	724
Operating income	222	142
Other income and (deductions)		
Interest expense, net	(30)	(30)
Interest expense to affiliates	(3)	(3)
Other, net	4	2
Total other income and (deductions)	(29)	(31)
Income before income taxes	193	111
Income taxes	25	(2)
Net income	$168	$113
Comprehensive income	$168	$113

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

	Three Months Ended March 31,	
(In millions)	2019	2018
Cash flows from operating activities		
Net income	$168	$113
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	81	75
Deferred income taxes and amortization of investment tax credits	5	(4)
Other non-cash operating activities	16	21
Changes in assets and liabilities:		
Accounts receivable	(86)	(51)
Receivables from and payables to affiliates, net	7	7
Inventories	23	12
Accounts payable and accrued expenses	(13)	6
Income taxes	20	5
Pension and non-pension postretirement benefit contributions	(25)	(24)
Other assets and liabilities	(119)	(141)
Net cash flows provided by operating activities	77	19
Cash flows from investing activities		
Capital expenditures	(222)	(217)
Other investing activities	2	2
Net cash flows used in investing activities	(220)	(215)
Cash flows from financing activities		
Changes in short-term borrowings	—	220
Issuance of long-term debt	—	325
Retirement of long-term debt	—	(500)
Changes in Exelon intercompany money pool	—	194
Contributions from parent	145	—
Dividends paid on common stock	(90)	(287)
Other financing activities	—	(5)
Net cash flows provided by (used in) financing activities	55	(53)
Decrease in cash, cash equivalents and restricted cash	(88)	(249)
Cash, cash equivalents and restricted cash at beginning of period	135	275
Cash, cash equivalents and restricted cash at end of period	$47	$26

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

(In millions)	March 31, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	$ 41	$ 130
Restricted cash and cash equivalents	6	5
Accounts receivable, net		
Customer	394	321
Other	148	151
Inventories, net		
Fossil fuel	15	38
Materials and supplies	37	37
Prepaid utility taxes	100	—
Regulatory assets	54	81
Other	21	19
Total current assets	816	782
Property, plant and equipment, net	8,766	8,610
Deferred debits and other assets		
Regulatory assets	491	460
Investments	25	25
Receivable from affiliates	457	389
Prepaid pension asset	372	349
Other	29	27
Total deferred debits and other assets	1,374	1,250
Total assets	$ 10,956	$ 10,642

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

(In millions)	March 31, 2019	December 31, 2018
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable	379	370
Accrued expenses	119	113
Payables to affiliates	66	59
Customer deposits	68	68
Regulatory liabilities	123	175
Other	32	24
Total current liabilities	787	809
Long-term debt	3,084	3,084
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,974	1,933
Asset retirement obligations	27	27
Non-pension postretirement benefits obligations	288	288
Regulatory liabilities	488	421
Other	81	76
Total deferred credits and other liabilities	2,858	2,745
Total liabilities	6,913	6,822
Commitments and contingencies		
Shareholder’s equity		
Common stock	2,723	2,578
Retained earnings	1,320	1,242
Total shareholder’s equity	4,043	3,820
Total liabilities and shareholder's equity	$ 10,956	$ 10,642

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

	Three months ended March 31, 2019			
(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	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

	Three months ended March 31, 2018			
(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	Total Shareholder's Equity
Balance, December 31, 2017	$2,489	$1,087	$ 1	$ 3,577
Net income	—	113	—	113
Common stock dividends	—	(287)	—	(287)
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities Standard	—	1	(1)	—
Balance, March 31, 2018	$2,489	$914	$ —	$ 3,403

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

	Three Months Ended March 31,	
(In millions)	2019	2018
Operating revenues		
Electric operating revenues	$652	$654
Natural gas operating revenues	308	330
Revenues from alternative revenue programs	10	(13)
Operating revenues from affiliates	6	6
Total operating revenues	976	977
Operating expenses		
Purchased power	190	192
Purchased fuel	95	123
Purchased power from affiliate	75	65
Operating and maintenance	153	184
Operating and maintenance from affiliates	39	37
Depreciation and amortization	136	134
Taxes other than income	68	65
Total operating expenses	756	800
Operating income	220	177
Other income and (deductions)		
Interest expense, net	(29)	(25)
Other, net	5	4
Total other income and (deductions)	(24)	(21)
Income before income taxes	196	156
Income taxes	36	28
Net income	$160	$128
Comprehensive income	$160	$128

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

	Three Months Ended March 31,	
(In millions)	2019	2018
Cash flows from operating activities		
Net income	$160	$128
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	136	134
Deferred income taxes and amortization of investment tax credits	28	22
Other non-cash operating activities	27	20
Changes in assets and liabilities:		
Accounts receivable	(39)	(32)
Receivables from and payables to affiliates, net	(10)	—
Inventories	17	20
Accounts payable and accrued expenses	(27)	(9)
Collateral posted, net	(1)	—
Income taxes	8	14
Pension and non-pension postretirement benefit contributions	(40)	(45)
Other assets and liabilities	(14)	61
Net cash flows provided by operating activities	245	313
Cash flows from investing activities		
Capital expenditures	(258)	(224)
Other investing activities	1	1
Net cash flows used in investing activities	(257)	(223)
Cash flows from financing activities		
Changes in short-term borrowings	71	(32)
Dividends paid on common stock	(56)	(52)
Net cash flows provided by (used in) financing activities	15	(84)
Increase in cash, cash equivalents and restricted cash	3	6
Cash, cash equivalents and restricted cash at beginning of period	13	18
Cash, cash equivalents and restricted cash at end of period	$16	$24

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BALTIMORE GAS AND ELECTRIC COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	$ 12	$ 7
Restricted cash and cash equivalents	4	6
Accounts receivable, net		
Customer	385	353
Other	89	90
Receivables from affiliates	—	1
Inventories, net		
Fossil fuel	16	36
Materials and supplies	42	39
Prepaid utility taxes	38	74
Regulatory assets	161	177
Other	6	3
Total current assets	753	786
Property, plant and equipment, net	8,408	8,243
Deferred debits and other assets		
Regulatory assets	395	398
Investments	5	5
Prepaid pension asset	301	279
Other	105	5
Total deferred debits and other assets	806	687
Total assets	$ 9,967	$ 9,716

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BALTIMORE GAS AND ELECTRIC COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2019	December 31, 2018
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current liabilities		
Short-term borrowings	$ 106	$ 35
Accounts payable	291	295
Accrued expenses	142	155
Payables to affiliates	54	65
Customer deposits	120	120
Regulatory liabilities	67	77
Other	54	27
Total current liabilities	834	774
Long-term debt	2,876	2,876
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,275	1,222
Asset retirement obligations	24	24
Non-pension postretirement benefits obligations	198	201
Regulatory liabilities	1,172	1,192
Other	130	73
Total deferred credits and other liabilities	2,799	2,712
Total liabilities	6,509	6,362
Commitments and contingencies		
Shareholders’ equity		
Common stock	1,714	1,714
Retained earnings	1,744	1,640
Total shareholders' equity	3,458	3,354
Total liabilities and shareholders’ equity	$ 9,967	$ 9,716

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

	Three Months Ended March 31, 2019		
(In millions)	Common Stock	Retained Earnings	Total Shareholders' 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

	Three Months Ended March 31, 2018		
(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity
Balance, December 31, 2017	$1,605	$1,536	$ 3,141
Net income	—	128	128
Common stock dividends	—	(52)	(52)
Balance, March 31, 2018	$1,605	$1,612	$ 3,217

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

	Three Months Ended March 31,	
(In millions)	2019	2018
Operating revenues		
Electric operating revenues	$1,139	$1,151
Natural gas operating revenues	71	78
Revenues from alternative revenue programs	15	18
Operating revenues from affiliates	3	4
Total operating revenues	1,228	1,251
Operating expenses		
Purchased power	355	374
Purchased fuel	34	41
Purchased power and fuel from affiliates	101	105
Operating and maintenance	239	271
Operating and maintenance from affiliates	33	38
Depreciation, amortization and accretion	180	183
Taxes other than income	111	113
Total operating expenses	1,053	1,125
Operating income	175	126
Other income and (deductions)		
Interest expense, net	(65)	(63)
Other, net	12	11
Total other income and (deductions)	(53)	(52)
Income before income taxes	122	74
Income taxes	5	9
Net income	$117	$65
Comprehensive income	$117	$65

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

(In millions)	Three Months Ended March 31, 2019	2018
Cash flows from operating activities		
Net income	$117	$65
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	180	183
Deferred income taxes and amortization of investment tax credits	—	17
Other non-cash operating activities	35	53
Changes in assets and liabilities:		
Accounts receivable	(11)	(9)
Receivables from and payables to affiliates, net	(8)	10
Inventories	(12)	4
Accounts payable and accrued expenses	(9)	44
Income taxes	4	(9)
Pension and non-pension postretirement benefit contributions	(6)	(55)
Other assets and liabilities	(61)	(24)
Net cash flows provided by operating activities	229	279
Cash flows from investing activities		
Capital expenditures	(358)	(258)
Other investing activities	1	—
Net cash flows used in investing activities	(357)	(258)
Cash flows from financing activities		
Changes in short-term borrowings	147	57
Retirement of long-term debt	(5)	(12)
Distributions to member	(128)	(71)
Contributions from member	19	—
Change in Exelon intercompany money pool	—	13
Net cash flows provided by (used in) financing activities	33	(13)
(Decrease) increase in cash, cash equivalents and restricted cash	(95)	8
Cash, cash equivalents and restricted cash at beginning of period	186	95
Cash, cash equivalents and restricted cash at end of period	$91	$103

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	March 31, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	$33	$ 124
Restricted cash and cash equivalents	39	43
Accounts receivable, net		
Customer	445	453
Other	189	177
Receivable from affiliates	1	—
Inventories, net		
Fossil Fuel	2	9
Materials and supplies	184	163
Regulatory assets	506	489
Other	54	75
Total current assets	1,453	1,533
Property, plant and equipment, net	13,619	13,446
Deferred debits and other assets		
Regulatory assets	2,236	2,312
Investments	132	130
Goodwill	4,005	4,005
Prepaid pension asset	467	486
Deferred income taxes	12	12
Other	370	60
Total deferred debits and other assets	7,222	7,005
Total assets[(a)]	$22,294	$ 21,984

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

(In millions)	March 31, 2019	December 31, 2018
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Short-term borrowings	$326	$ 179
Long-term debt due within one year	125	125
Accounts payable	441	496
Accrued expenses	253	256
Payables to affiliates	87	94
Regulatory liabilities	76	84
Unamortized energy contract liabilities	123	119
Customer deposits	117	116
Other	127	123
Total current liabilities	1,675	1,592
Long-term debt	6,119	6,134
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,182	2,146
Asset retirement obligations	52	52
Non-pension postretirement benefit obligations	101	103
Regulatory liabilities	1,829	1,864
Unamortized energy contract liabilities	416	442
Other	630	369
Total deferred credits and other liabilities	5,210	4,976
Total liabilities[(a)]	13,004	12,702
Commitments and contingencies		
Member's equity		
Membership interest	9,239	9,220
Undistributed earnings	51	62
Total member's equity	9,290	9,282
Total liabilities and member's equity	$22,294	$ 21,984

(a) PHI’s consolidated total assets include $31 million and $33 million at March 31, 2019 and December 31, 2018, respectively, of PHI's consolidated VIE that can only be used to settle the liabilities of the VIE. PHI’s consolidated total liabilities include $64 million and $69 million at March 31, 2019 and December 31, 2018, respectively, of PHI's consolidated VIE for which the VIE creditors do not have recourse to PHI. See Note 2 — Variable Interest Entities for additional information.

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

	Three Months Ended March 31, 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

	Three Months Ended March 31, 2018		
(In millions)	Membership Interest	Undistributed Earnings (Losses)	Member's Equity
Balance, December 31, 2017	$8,835	$ (10)	$ 8,825
Net income	—	65	65
Distributions to member	—	(71)	(71)
Balance, March 31, 2018	$8,835	$ (16)	$ 8,819

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

	Three Months Ended March 31,	
(In millions)	2019	2018
Operating revenues		
Electric operating revenues	$559	$536
Revenues from alternative revenue programs	14	19
Operating revenues from affiliates	2	2
Total operating revenues	575	557
Operating expenses		
Purchased power	117	130
Purchased power from affiliates	70	52
Operating and maintenance	64	73
Operating and maintenance from affiliates	54	57
Depreciation and amortization	94	96
Taxes other than income	92	93
Total operating expenses	491	501
Operating income	84	56
Other income and (deductions)		
Interest expense, net	(34)	(31)
Other, net	7	8
Total other income and (deductions)	(27)	(23)
Income before income taxes	57	33
Income taxes	2	2
Net income	$55	$31
Comprehensive income	$55	$31

See the Combined Notes to Consolidated Financial Statements

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POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Three Months Ended March 31, 2019	2018
Cash flows from operating activities		
Net income	$55	$31
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	94	96
Deferred income taxes and amortization of investment tax credits	(2)	4
Other non-cash operating activities	3	10
Changes in assets and liabilities:		
Accounts receivable	(19)	—
Receivables from and payables to affiliates, net	3	(18)
Inventories	(14)	(2)
Accounts payable and accrued expenses	(2)	36
Income taxes	4	(3)
Pension and non-pension postretirement benefit contributions	(4)	(7)
Other assets and liabilities	(37)	(21)
Net cash flows provided by operating activities	81	126
Cash flows from investing activities		
Capital expenditures	(144)	(127)
Other investing activities	1	—
Net cash flows used in investing activities	(143)	(127)
Cash flows from financing activities		
Changes in short-term borrowings	65	34
Dividends paid on common stock	(24)	(25)
Contributions from parent	14	—
Net cash flows provided by financing activities	55	9
(Decrease) increase in cash, cash equivalents and restricted cash	(7)	8
Cash, cash equivalents and restricted cash at beginning of period	53	40
Cash, cash equivalents and restricted cash at end of period	$46	$48

See the Combined Notes to Consolidated Financial Statements

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POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	$ 11	$ 16
Restricted cash and cash equivalents	35	37
Accounts receivable, net		
Customer	219	225
Other	102	81
Receivables from affiliates	1	1
Inventories, net	109	93
Regulatory assets	270	270
Other	22	37
Total current assets	769	760
Property, plant and equipment, net	6,534	6,460
Deferred debits and other assets		
Regulatory assets	620	643
Investments	106	105
Prepaid pension asset	311	316
Other	80	15
Total deferred debits and other assets	1,117	1,079
Total assets	$ 8,420	$ 8,299

See the Combined Notes to Consolidated Financial Statements

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POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2019	December 31, 2018
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 105	$ 40
Long-term debt due within one year	15	15
Accounts payable	188	214
Accrued expenses	139	126
Payables to affiliates	65	62
Customer deposits	55	54
Regulatory liabilities	6	7
Merger related obligation	38	38
Current portion of DC PLUG obligation	30	30
Other	17	42
Total current liabilities	658	628
Long-term debt	2,705	2,704
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,081	1,064
Non-pension postretirement benefit obligations	26	29
Regulatory liabilities	805	822
Other	360	312
Total deferred credits and other liabilities	2,272	2,227
Total liabilities	5,635	5,559
Commitments and contingencies		
Shareholder's equity		
Common stock	1,650	1,636
Retained earnings	1,135	1,104
Total shareholder's equity	2,785	2,740
Total liabilities and shareholder's equity	$ 8,420	$ 8,299

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

	Three Months Ended March 31, 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

	Three Months Ended March 31, 2018		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2017	$1,470	$1,063	$ 2,533
Net income	—	31	31
Common stock dividends	—	(25)	(25)
Balance, March 31, 2018	$1,470	$1,069	$ 2,539

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

	Three Months Ended March 31,	
(In millions)	2019	2018
Operating revenues		
Electric operating revenues	$307	$303
Natural gas operating revenues	71	78
Revenues from alternative revenue programs	—	1
Operating revenues from affiliates	2	2
Total operating revenues	380	384
Operating expenses		
Purchased power	107	90
Purchased fuel	34	41
Purchased power from affiliate	23	46
Operating and maintenance	45	57
Operating and maintenance from affiliates	39	41
Depreciation and amortization	46	45
Taxes other than income	14	15
Total operating expenses	308	335
Operating income	72	49
Other income and (deductions)		
Interest expense, net	(15)	(13)
Other, net	3	2
Total other income and (deductions)	(12)	(11)
Income before income taxes	60	38
Income taxes	7	7
Net income	$53	$31
Comprehensive income	$53	$31

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended March 31, 2019	2018
Cash flows from operating activities		
Net income	$53	$31
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	46	45
Deferred income taxes and amortization of investment tax credits	1	10
Other non-cash operating activities	11	19
Changes in assets and liabilities:		
Accounts receivable	(5)	(1)
Receivables from and payables to affiliates, net	(15)	(16)
Inventories	1	7
Accounts payable and accrued expenses	11	18
Income taxes	5	(5)
Other assets and liabilities	(10)	7
Net cash flows provided by operating activities	98	115
Cash flows from investing activities		
Capital expenditures	(78)	(65)
Net cash flows used in investing activities	(78)	(65)
Cash flows from financing activities		
Changes in short-term borrowings	5	(5)
Retirement of long-term debt	—	(4)
Dividends paid on common stock	(41)	(36)
Net cash flows used in financing activities	(36)	(45)
(Decrease) increase in cash, cash equivalents and restricted cash	(16)	5
Cash, cash equivalents and restricted cash at beginning of period	24	2
Cash, cash equivalents and restricted cash at end of period	$8	$7

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DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	$ 7	$ 23
Restricted cash and cash equivalents	1	1
Accounts receivable, net		
Customer	141	134
Other	39	46
Receivables from affiliates	2	—
Inventories, net		
Fossil Fuel	2	9
Materials and supplies	43	37
Regulatory assets	60	59
Other	21	27
Total current assets	316	336
Property, plant and equipment, net	3,848	3,821
Deferred debits and other assets		
Regulatory assets	225	231
Goodwill	8	8
Prepaid pension asset	182	186
Other	81	6
Total deferred debits and other assets	496	431
Total assets	$ 4,660	$ 4,588

See the Combined Notes to Consolidated Financial Statements

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DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2019	December 31, 2018
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 5	$ —
Long-term debt due within one year	91	91
Accounts payable	98	111
Accrued expenses	50	39
Payables to affiliates	21	33
Customer deposits	36	35
Regulatory liabilities	49	59
Other	16	7
Total current liabilities	366	375
Long-term debt	1,404	1,403
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	643	628
Non-pension postretirement benefits obligations	16	17
Regulatory liabilities	596	606
Other	114	50
Total deferred credits and other liabilities	1,369	1,301
Total liabilities	3,139	3,079
Commitments and contingencies		
Shareholder's equity		
Common stock	914	914
Retained earnings	607	595
Total shareholder's equity	1,521	1,509
Total liabilities and shareholder's equity	$ 4,660	$ 4,588

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

	Three Months Ended March 31, 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

	Three Months Ended March 31, 2018		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2017	$764	$ 571	$ 1,335
Net income	—	31	31
Common stock dividends	—	(36)	(36)
Balance, March 31, 2018	$764	$ 566	$ 1,330

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

	Three Months Ended March 31,	
(In millions)	2019	2018
Operating revenues		
Electric operating revenues	$271	$311
Revenues from alternative revenue programs	1	(2)
Operating revenues from affiliates	1	1
Total operating revenues	273	310
Operating expenses		
Purchased power	131	155
Purchased power from affiliates	8	6
Operating and maintenance	47	54
Operating and maintenance from affiliates	34	36
Depreciation and amortization	31	33
Taxes other than income	1	3
Total operating expenses	252	287
Operating income	21	23
Other income and (deductions)		
Interest expense, net	(14)	(16)
Other, net	3	1
Total other income and (deductions)	(11)	(15)
Income before income taxes	10	8
Income taxes	—	1
Net income	$10	$7
Comprehensive income	$10	$7

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

	Three Months Ended March 31,	
(In millions)	2019	2018
Cash flows from operating activities		
Net income	$10	$7
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	31	33
Deferred income taxes and amortization of investment tax credits	—	2
Other non-cash operating activities	5	9
Changes in assets and liabilities:		
Accounts receivable	13	(5)
Receivables from and payables to affiliates, net	(4)	(4)
Inventories	1	—
Accounts payable and accrued expenses	12	30
Income taxes	(1)	—
Pension and non-pension postretirement benefit contributions	—	(6)
Other assets and liabilities	(7)	(7)
Net cash flows provided by operating activities	60	59
Cash flows from investing activities		
Capital expenditures	(128)	(63)
Other investing activities	—	(1)
Net cash flows used in investing activities	(128)	(64)
Cash flows from financing activities		
Changes in short-term borrowings	77	28
Retirement of long-term debt	(4)	(8)
Dividends paid on common stock	(12)	(9)
Contributions from parent	5	—
Net cash flows provided by financing activities	66	11
(Decrease) increase in cash, cash equivalents and restricted cash	(2)	6
Cash, cash equivalents and restricted cash at beginning of period	30	31
Cash, cash equivalents and restricted cash at end of period	$28	$37

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

(In millions)	March 31, 2019	December 31, 2018
ASSETS		
Current assets		
Cash and cash equivalents	$ 6	$ 7
Restricted cash and cash equivalents	3	4
Accounts receivable, net		
Customer	85	95
Other	52	55
Receivables from affiliates	1	1
Inventories, net	32	33
Regulatory assets	53	40
Other	6	5
Total current assets	238	240
Property, plant and equipment, net	3,041	2,966
Deferred debits and other assets		
Regulatory assets	377	386
Prepaid pension asset	63	67
Other	64	40
Total deferred debits and other assets	504	493
Total assets[(a)]	$ 3,783	$ 3,699

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	March 31, 2019	December 31, 2018
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 216	$ 139
Long-term debt due within one year	19	18
Accounts payable	139	154
Accrued expenses	38	35
Payables to affiliates	24	28
Customer deposits	26	26
Regulatory liabilities	20	18
Other	10	4
Total current liabilities	492	422
Long-term debt	1,165	1,170
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	539	535
Non-pension postretirement benefit obligations	17	17
Regulatory liabilities	395	402
Other	46	27
Total deferred credits and other liabilities	997	981
Total liabilities[(a)]	2,654	2,573
Commitments and contingencies		
Shareholder's equity		
Common stock	984	979
Retained earnings	145	147
Total shareholder's equity	1,129	1,126
Total liabilities and shareholder's equity	$ 3,783	$ 3,699

(a) ACE's consolidated total assets include $22 million and $23 million at March 31, 2019 and December 31, 2018, respectively, of ACE's consolidated VIE that can only be used to settle the liabilities of the VIE. ACE's consolidated total liabilities include $54 million and $59 million at March 31, 2019 and December 31, 2018, respectively, of ACE's consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 2 — Variable Interest Entities for additional information.

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

	Three Months Ended March 31, 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

	Three Months Ended March 31, 2018		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2017	$912	$ 131	$ 1,043
Net income	—	7	7
Common stock dividends	—	(9)	(9)
Balance, March 31, 2018	$912	$ 129	$ 1,041

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

Index to Combined Notes To Consolidated Financial Statements

The notes to the consolidated financial statements that follow are a combined presentation. The following list indicates the Registrants to which the footnotes apply:

Applicable Notes

Registrant	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
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	.	.		.	.	.			.	.	.	.		.		.	.	.
Atlantic City Electric Company	.	.		.	.	.			.	.	.	.		.		.	.	.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(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
	Purchase and regulated retail sale of electricity	

Potomac Electric Power Company		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 March 31, 2019 and 2018 and for the three months then ended are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants' respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2018 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, 2019. 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

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normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations.

New Accounting Standards (All Registrants)

New Accounting Standards Adopted in 2019: In 2019, the Registrants have adopted the following new authoritative accounting guidance issued by the FASB.

Leases. The Registrants applied the new guidance with the following transition practical expedients:

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

The standard materially impacted the Registrants' Consolidated Balance Sheets but did not have a material impact in the Registrants' Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and Consolidated Statements of Changes in Shareholders' Equity. The most significant impact was the recognition of the ROU assets and lease liabilities for operating leases. The operating ROU assets and lease liabilities recognized upon adoption are materially consistent with the balances presented in the Combined Notes to the Consolidated Financial Statements. See Note 5 - Leases for additional information.

See Note 1 — Significant Accounting Policies of the Exelon 2018 Form 10-K for additional information on new accounting standards issued and adopted as of January 1, 2019.

New Accounting Standards Issued and Not Yet Adopted as of March 31, 2019: The following new authoritative accounting guidance issued by the FASB has not yet been adopted and reflected by the Registrants in their consolidated financial statements as of March 31, 2019. Unless otherwise indicated, the Registrants are currently assessing the impacts such guidance may have (which could be material) in their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures, as well as the potential to early adopt where applicable. The Registrants have assessed other FASB issuances of new standards which are not listed below given the current expectation that such standards will not significantly impact the Registrants' financial reporting.

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. Exelon, Generation, ComEd, PHI and DPL have goodwill as of March 31, 2019. This updated guidance is not currently expected to impact the Registrants’ financial reporting. The standard is effective January 1, 2020, with early adoption permitted, and must be applied on a prospective basis.

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 the entity’s current estimate of credit losses expected to be incurred over the life of the financial instrument. The standard does not make changes to the existing impairment models for non-financial assets such as fixed assets, intangibles and goodwill. The standard will be effective January 1, 2020 (with early adoption as of January 1, 2019 permitted) and requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption. The Registrants are currently assessing the impacts of this standard.

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Leases (All Registrants)

The Registrants recognize a ROU asset and lease liability for operating leases with a term of greater than one year. The ROU asset is included in Other deferred debits and other assets and the lease liability is included in Other current liabilities and Other deferred credits and other liabilities on the Consolidated Balance Sheets. The ROU asset is measured as the sum of (1) the present value of all remaining fixed and in-substance fixed payments using each Registrant's incremental borrowing rate, (2) any lease payments made at or before the commencement date (less any lease incentives received) and (3) any initial direct costs incurred. The lease liability is measured the same as the ROU asset, but excludes any payments made before the commencement date and initial direct costs incurred. Lease terms include options to extend or terminate the lease if it is reasonably certain they will be exercised. The Registrants include non-lease components, which are service-related costs that are not integral to the use of the asset, in the measurement of the ROU asset and lease liability.

Expense for operating leases and leases with a term of one year or less is recognized on a straight-line basis over the term of the lease, unless another systematic and rational basis is more representative of the derivation of benefit from use of the leased property. Variable lease payments are recognized in the period in which the related obligation is incurred and consist primarily of payments for purchases of electricity under contracted generation and are based on the electricity produced by those generating assets. Operating lease expense and variable lease payments are recorded to Purchased power and fuel expense for contracted generation or Operating and maintenance expense for all other lease agreements on the Registrants' Statements of Operations and Comprehensive Income.

Income from operating leases, including subleases, is recognized on a straight-line basis over the term of the lease, unless another systematic and rational basis is more representative of the pattern in which income is earned over the term of the lease. Variable lease payments are recognized in the period in which the related obligation is performed and consist primarily of payments received from sales of electricity under contracted generation and are based on the electricity produced by those generating assets. Operating lease income and variable lease payments are recorded to Operating revenues on the Registrants' Statements of Operations and Comprehensive Income.

The Registrants' operating leases consist primarily of contracted generation, real estate including office buildings, and vehicles and equipment. The Registrants generally account for contracted generation in which the generating asset is not renewable as a lease if the customer has dispatch rights and obtains substantially all of the economic benefits. For new agreements entered after January 1, 2019, the Registrants will generally not account for contracted generation in which the generating asset is renewable as a lease if the customer does not design the generating asset. The Registrants account for land right arrangements that provide for exclusive use as leases while shared use land arrangements are generally not leases. The Registrants do not account for secondary use pole attachments as leases. See Note 5 —Leases for additional information.

2. Variable Interest Entities (All Registrants)

A VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest) or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly affect the entity's economic performance.

At March 31, 2019 and December 31, 2018, Exelon, Generation, PHI and ACE collectively consolidated five VIEs or VIE groups for which the applicable Registrant was the primary beneficiary (see Consolidated Variable Interest Entities below). As of March 31, 2019 and December 31, 2018, Exelon and Generation collectively had significant interests in seven 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 Variable Interest Entities below).

Consolidated Variable Interest Entities

As of March 31, 2019 and December 31, 2018, Exelon's and Generation's consolidated VIEs consist of:

- energy related companies involved in distributed generation, backup generation and energy development
- renewable energy project companies formed by Generation to build, own and operate renewable power facilities
- certain retail power and gas companies for which Generation is the sole supplier of energy, and
- CENG.

As of March 31, 2019 and December 31, 2018, Exelon's, PHI's and ACE's consolidated VIE consist of:

- ATF, 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.

As of March 31, 2019 and December 31, 2018, ComEd, PECO, BGE, Pepco and DPL did not have any material consolidated VIEs.

As of March 31, 2019 and December 31, 2018, Exelon and Generation provided the following support to their respective consolidated VIEs:

- Generation provides operating and capital funding to the renewable energy project companies and there is limited recourse to Generation related to certain renewable energy project companies.
- Generation provides approximately $32 million in credit support for the retail power and gas companies for which Generation is the sole supplier of energy.
- Exelon and Generation, where indicated, provide the following support to CENG:
- under PPAs with CENG, Generation purchased or will purchase 50.01% of the available output generated by the CENG nuclear plants not subject to other contractual agreements from January 2015 through the end of the operating life of each respective plant. However, pursuant to amendments dated March 31, 2015, the energy obligations under the Ginna Nuclear Power Plant (Ginna) PPAs were suspended during the term of the RSSA, through the end of March 31, 2017. With the expiration of the RSSA, the PPA was reinstated beginning April 1, 2017,
- Generation provided a $400 million loan to CENG. The loan balance was fully repaid by CENG in January 2019.
- 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 16 — Commitments and Contingencies for additional information),
- 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.

As of March 31, 2019 and December 31, 2018, Exelon, PHI and ACE provided the following support to their respective consolidated VIE:

- In the case of ATF, 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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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NJBPU in an amount sufficient to fund the principal and interest payments on transition bonds and related taxes, expenses and fees. During the three months ended March 31, 2019, ACE transferred $4 million to ATF. During the three months ended March 31, 2018, ACE transferred $8 million to ATF.
For each of the consolidated VIEs, except as otherwise noted:
- the assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE;
- Exelon, Generation, PHI and ACE did not provide any additional material financial support to the VIEs;
- Exelon, Generation, PHI and ACE did not have any material contractual commitments or obligations to provide financial support to the VIEs; and
- the creditors of the VIEs did not have recourse to Exelon’s, Generation’s, PHI's or ACE's general credit.

The carrying amounts and classification of the consolidated VIEs’ assets and liabilities included in the Registrants' consolidated financial statements at March 31, 2019 and December 31, 2018 are as follows:

	March 31, 2019				December 31, 2018			
	Exelon[(a)]	Generation	PHI[(a)]	ACE	Exelon[(a)]	Generation	PHI[(a)]	ACE
Current assets	$645	$ 639	$ 6	$ 3	$938	$ 931	$ 7	$ 4
Noncurrent assets	9,235	9,210	25	19	9,071	9,045	26	19
Total assets	$9,880	$ 9,849	$ 31	$ 22	$10,009	$ 9,976	$ 33	$ 23
Current liabilities	$748	$ 725	$ 23	$ 19	$274	$ 252	$ 22	$ 19
Noncurrent liabilities	2,831	2,790	41	35	3,280	3,233	47	40
Total liabilities	$3,579	$ 3,515	$ 64	$ 54	$3,554	$ 3,485	$ 69	$ 59

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

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Assets and Liabilities of Consolidated VIEs

Included within the balances above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors or beneficiaries do not have recourse to the general credit of the Registrants. As of March 31, 2019 and December 31, 2018, these assets and liabilities primarily consisted of the following:

	March 31, 2019				December 31, 2018			
	Exelon[(a)]	Generation	PHI[(a)]	ACE	Exelon[(a)]	Generation	PHI[(a)]	ACE
Cash and cash equivalents	$125	$ 125	$ —	$ —	$414	$ 414	$ —	$ —
Restricted cash and cash equivalents	58	55	3	3	66	62	4	4
Accounts receivable, net								
Customer	152	152	—	—	146	146	—	—
Other	23	23	—	—	23	23	—	—
Inventory, net								
Materials and supplies	213	213	—	—	212	212	—	—
Other current assets	51	48	3	—	52	49	3	—
Total current assets	622	616	6	3	913	906	7	4
Property, plant and equipment, net	6,147	6,147	—	—	6,145	6,145	—	—
NDT funds	2,520	2,520	—	—	2,351	2,351	—	—
Other noncurrent assets	257	232	25	19	258	232	26	19
Total noncurrent assets	8,924	8,899	25	19	8,754	8,728	26	19
Total assets	$9,546	$ 9,515	$ 31	$ 22	$9,667	$ 9,634	$ 33	$ 23
Long-term debt due within one year	$567	$ 545	$ 22	$ 19	$87	$ 66	$ 21	$ 18
Accounts payable	120	120	—	—	96	96	—	—
Accrued expenses	42	41	1	—	72	72	1	1
Unamortized energy contract liabilities	13	13	—	—	15	15	—	—
Other current liabilities	6	6	—	—	3	3	—	—
Total current liabilities	748	725	23	19	273	252	22	19
Long-term debt	565	524	41	35	1,072	1,025	47	40
Asset retirement obligations	2,190	2,190	—	—	2,160	2,160	—	—
Unamortized energy contract liabilities	—	—	—	—	1	1	—	—
Other noncurrent liabilities	69	69	—	—	42	42	—	—
Total noncurrent liabilities	2,824	2,783	41	35	3,275	3,228	47	40
Total liabilities	$3,572	$ 3,508	$ 64	$ 54	$3,548	$ 3,480	$ 69	$ 59

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

Unconsolidated Variable Interest Entities

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

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(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. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

As of March 31, 2019 and December 31, 2018, Exelon's and Generation's unconsolidated VIEs consist of:

- Energy purchase and sale agreements with VIEs for which Generation has concluded that consolidation is not required.
- Asset sale agreement with ZionSolutions, LLC and EnergySolutions, Inc. in which Generation has a variable interest but has concluded that consolidation is not required.
- Equity investments in distributed energy companies for which Generation has concluded that consolidation is not required.

As of March 31, 2019 and December 31, 2018, the Utility Registrants did not have any material unconsolidated VIEs.

As of March 31, 2019 and December 31, 2018, Exelon and Generation had significant unconsolidated variable interests in seven VIEs for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity investments and certain commercial agreements. Exelon and Generation only include unconsolidated VIEs that are individually material in the tables below. However, Exelon and Generation have several individually immaterial VIEs that in aggregate represent a total investment of $16 million and $12 million, respectively, as of March 31, 2019. These immaterial VIEs are equity and debt securities in energy development companies. As of March 31, 2019, the maximum exposure to loss related to these securities included in Investments in Exelon’s and Generation’s Consolidated Balance Sheets is limited to $16 million and $12 million, respectively. The risk of a loss was assessed to be remote and, accordingly, Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss.

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The following tables present summary information about Exelon's and Generation's significant unconsolidated VIE entities:

March 31, 2019	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 601	$ 463	$1,064
Total liabilities[(a)]	42	223	265
Exelon's ownership interest in VIE[(a)]	—	214	214
Other ownership interests in VIE[(a)]	559	26	585
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	214	214
Contract intangible asset	7	—	7

December 31, 2018	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 597	$ 472	$1,069
Total liabilities[(a)]	37	222	259
Exelon's ownership interest in VIE[(a)]	—	223	223
Other ownership interests in VIE[(a)]	560	27	587
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	223	223
Contract intangible asset	7	—	7

(a) These items represent amounts in 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.

For each of the unconsolidated VIEs, Exelon and Generation have assessed the risk of a loss equal to their maximum exposure to be remote and, accordingly, Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no material agreements with, or commitments by, third parties that would affect the fair value or risk of their variable interests in these VIEs.

3. Mergers, Acquisitions and Dispositions (Exelon and Generation)

Disposition of Oyster Creek

On July 31, 2018, Generation entered into an agreement with Holtec International (Holtec) and its indirect wholly owned subsidiary, Oyster Creek Environmental Protection, LLC (OCEP), for the sale and decommissioning of Oyster Creek located in Forked River, New Jersey. On September 17, 2018, Oyster Creek permanently ceased generation operations.

Under the terms of the transaction, Generation will transfer to OCEP substantially all the assets associated with Oyster Creek, including assets held in NDT funds, along with the assumption of liability for all responsibility for the site, including full decommissioning and ongoing management of spent fuel until the spent fuel is moved offsite. In addition to the assumption of liability for the full decommissioning and ongoing management of spent fuel, other consideration to be received in the transaction is contingent on several factors, including a requirement that Generation deliver a minimum NDT fund balance at closing, subject to adjustment for specific terms that include income taxes that would be imposed on any net unrealized built-in gains and certain decommissioning activities to be performed during the pre-close period after the unit shuts down in the fall of 2018 and prior to the anticipated close of the transaction. The terms of the transaction also include various forms of performance assurance for the obligations of OCEP to timely complete the required decommissioning, including a parental guaranty from Holtec for all performance and payment obligations of OCEP, and a requirement for Holtec to deliver a letter of credit to Generation upon the occurrence of specified events.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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As a result of the transaction, in the third quarter of 2018, Exelon and Generation reclassified certain Oyster Creek assets and liabilities in Exelon’s and Generation’s Consolidated Balance Sheets as held for sale at their respective fair values. Exelon and Generation had $888 million and $765 million of Assets and Liabilities held for sale, respectively, at March 31, 2019 and $897 million and $777 million of Assets and Liabilities held for sale, respectively, at December 31, 2018. Upon remeasurement of the Oyster Creek ARO in the third quarter of 2018, Exelon and Generation recognized an $84 million pre-tax charge to Operating and maintenance expense.

Completion of the transaction contemplated by the sale agreement is subject to the satisfaction of several closing conditions, including approval of the license transfer from the NRC and other regulatory approvals, and a private letter ruling from the IRS, which was received in April 2019. Generation currently anticipates satisfaction of the remaining closing conditions to occur in the second half of 2019.

Other Asset Disposition

On February 28, 2018, Generation completed the sale of its interest in an electrical contracting business that primarily installs, maintains and repairs underground and high-voltage cable transmission and distribution systems for $87 million, resulting in a pre-tax gain which is included within Gain on sales of assets and businesses in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the three months ended March 31, 2018. In June 2018, additional proceeds were received, and a pre-tax gain was recorded within Gain on sales of assets and businesses in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

4. Revenue from Contracts with Customers (All Registrants)

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

See Note 3 — Revenue from Contracts with Customers of the Exelon 2018 Form 10-K for additional information regarding the primary sources of revenue for the Registrants.

Contract Balances (All Registrants)

Contract Assets and Liabilities

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

Generation records contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. These contract liabilities primarily relate to upfront consideration received or due for equipment service plans, solar panel leases and the Illinois ZEC program that introduces a cap on the total consideration to be received by Generation. Generation records contract liabilities within Other current liabilities and Other noncurrent liabilities within Exelon's and Generation's Consolidated Balance Sheets.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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The following table provides a rollforward of the contract assets and liabilities reflected in Exelon's and Generation's Consolidated Balance Sheets from January 1, 2018 to March 31, 2019:

	Contract Assets		Contract Liabilities	
	Exelon	Generation	Exelon	Generation
Balance as of January 1, 2018	$283	$ 283	$35	$ 35
Increases as a result of changes in the estimate of the stage of completion	50	50	—	—
Increases as a result of additional cash received or due	—	—	179	465
Amounts reclassified into receivables or recognized into revenues	(146)	(146)	(187)	(458)
Balance at December 31, 2018	187	187	27	42
Increases as a result of changes in the estimate of the stage of completion	26	26	—	—
Increases as a result of additional cash received or due	—	—	21	63
Amounts reclassified into receivables or recognized into revenues	(26)	(26)	(23)	(66)
Balance at March 31, 2019	$187	$ 187	$25	$ 39

The Utility Registrants do not have any contract assets. The Utility Registrants also record contract liabilities when consideration is received prior to the satisfaction of the performance obligations. As of March 31, 2019 and December 31, 2018, the Utility Registrants' contract liabilities were immaterial.

Transaction Price Allocated to Remaining Performance Obligations (All Registrants)

The following table shows the amounts of future revenues expected to be recorded in each year for performance obligations that are unsatisfied or partially unsatisfied as of March 31, 2019. 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.

	2019	2020	2021	2022	2023 and thereafter	Total
Exelon	$393	$273	$112	$ 50	$ 142	$970
Generation	493	331	126	50	142	1,142

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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5. Leases (All Registrants)

Lessee

The Registrants have operating leases for which they are the lessees. The following tables outline the significant types of operating leases at each registrant and other terms and conditions of the lease agreements. The Registrants do not have material finance leases.

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

(in years)	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Remaining lease terms	1-87	1-37	1-34	1-15	1-87	1-13	1-13	1-13	1-8
Options to extend the term	3-30	3-30	3-10	N/A	N/A	3-30	5	3-30	N/A
Options to terminate within	1-3	2	N/A	N/A	3	N/A	N/A	N/A	N/A

The components of lease costs for the three months ended March 31, 2019 were as follows:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Operating lease costs	$ 68	$ 46	$ 1	$ —	$ 8	$ 10	$ 3	$ 3	$ 1
Variable lease costs	73	68	—	—	—	2	—	1	—
Short-term lease costs	9	8	—	—	—	—	—	—	—
Total lease costs (a)	$ 150	$ 122	$ 1	$ —	$ 8	$ 12	$ 3	$ 4	$ 1

(a) Excludes $3 million, $2 million, $1 million and $1 million of sublease income recorded at Exelon, Generation, PHI and DPL.

The following table provides additional information regarding the presentation of operating lease ROU assets and lease liabilities within the Registrants’ Consolidated Balance Sheets as of March 31, 2019:

	Exelon(a)	Generation(a)	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Operating lease ROU assets									
Other deferred debits and other assets	$ 1,465	$ 1,027	$ 5	$ 2	$ 97	$ 314	$ 67	$ 75	$ 26
Operating lease liabilities									
Other current liabilities	249	173	3	1	31	36	8	11	6
Other deferred credits and other liabilities	1,395	1,023	4	1	66	284	60	72	20
Total operating lease liabilities	$ 1,644	$ 1,196	$ 7	$ 2	$ 97	$ 320	$ 68	$ 83	$ 26

(a) Exelon's and Generation's operating ROU assets and lease liabilities include $631 million and $778 million, respectively, related to contracted generation.

The weighted average remaining lease terms, in years, and discount rates for operating leases as of March 31, 2019 were as follows:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Remaining lease term	10.0	10.7	2.9	4.4	5.6	9.4	9.9	9.8	5.3
Discount rate	4.6 %	4.8 %	3.3 %	3.4 %	3.6 %	4.1 %	3.9 %	3.9 %	3.5 %

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Future minimum lease payments for operating leases as of March 31, 2019 were as follows:

Year	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2019	$214	$ 154	$ 2	$ 1	$ 19	$33	$ 8	$ 7	$ 5
2020	289	202	2	1	34	43	9	12	5
2021	244	162	2	—	32	42	9	11	5
2022	174	112	1	—	16	40	8	11	4
2023	139	99	—	—	—	39	8	10	3
Remaining years	1,052	840	—	—	18	194	42	52	7
Total	2,112	1,569	7	2	119	391	84	103	29
Interest	468	373	—	—	22	71	16	20	3
Total operating lease liabilities	$1,644	$ 1,196	$ 7	$ 2	$ 97	$320	$ 68	$ 83	$ 26

Future minimum lease payments for operating leases under the prior lease accounting guidance as of December 31, 2018 were as follows:

	Exelon(a)(b)	Generation(a)(b)	ComEd(a)(c)	PECO(a)(c)	BGE(a)(c)(d)(e)	PHI(a)	Pepco(a)	DPL(a)(c)	ACE(a)
2019	$ 140	$ 33	$ 7	$ 5	$ 35	$ 48	$ 11	$ 14	$ 7
2020	149	46	5	5	35	46	10	13	6
2021	143	46	4	5	33	43	9	12	5
2022	126	47	4	5	18	42	8	12	5
2023	97	46	3	5	3	39	8	10	4
Remaining years	723	545	—	—	19	159	40	35	5
Total minimum future lease payments	$ 1,378	$ 763	$ 23	$ 25	$ 143	$ 377	$ 86	$ 96	$ 32

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(a) Includes amounts related to shared use land arrangements.

(b) Excludes Generation's contingent operating lease payments associated with contracted generation.

(c) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, ComEd, PECO, BGE and DPL have excluded these payments from the remaining years as such amounts would not be meaningful. ComEd's, PECO's, BGE's and DPL's average annual obligation for these arrangements, included in each of the years 2019 - 2023, was $3 million, $5 million, $1 million and $1 million respectively. Also includes amounts related to shared use land arrangements.

(d) Includes all future lease payments on a 99-year real estate lease that expires in 2106.

(e) The BGE column above includes minimum future lease payments associated with a 6-year lease for the Baltimore City conduit system that became effective during the fourth quarter of 2016. BGE's total commitments under the lease agreement are $26 million, $28 million, $28 million and $14 million related to years 2019 - 2022, respectively.

Cash paid for amounts included in the measurement of lease liabilities for the three months ended March 31, 2019 were as follows:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Operating cash flows from operating leases	$ 78	$ 52	$ 1	$ —	$ 14	$ 8	$ 2	$ 2	$ 1

ROU assets obtained in exchange for lease obligations for the three months ended March 31, 2019 were as follows:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Operating leases	$ 20	$ 9	$ —	$ —	$ —	$ 11	$ 4	$ 4	$ 3

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Lessor

The Registrants have operating leases for which they are the lessors. The following tables outline the significant types of leases at each registrant and other terms and conditions of their lease agreements.

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

(in years)	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Remaining lease terms	1-84	1-33	1-18	1-84	24	1-14	2-7	13-14	1-3
Options to extend the term	1-79	1-5	5-79	5-50	N/A	5	N/A	N/A	N/A

The components of lease income for the three months ended March 31, 2019 were as follows:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Operating lease income	$ 4	$ 3	$ —	$ —	$ —	$ 1	$ —	$ 1	$ —
Variable lease income	$ 52	$ 52	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Future minimum lease payments to be recovered under operating leases as of March 31, 2019 were as follows:

Year	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2019	$ 47	$ 43	$ —	$ —	$ —	$ 4	$ —	$ 3	$ —
2020	51	46	—	—	—	4	—	3	—
2021	50	45	—	—	—	4	—	3	—
2022	50	45	—	—	—	4	—	3	—
2023	49	45	—	—	—	4	—	3	—
Remaining years	315	271	1	3	1	39	1	38	—
Total	$ 562	$ 495	$ 1	$ 3	$ 1	$ 59	$ 1	$ 53	$ —

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6. Regulatory Matters (All Registrants)
As discussed in Note 4 — Regulatory Matters of the Exelon 2018 Form 10-K, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The following discusses developments in 2019 and updates to the 2018 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 2019.
Completed Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement Increase	Approved Revenue Requirement Increase (Decrease)	Approved ROE	Approval Date	Rate Effective Date
BGE - Maryland (Natural Gas)	June 8, 2018 (amended October 12, 2018)	$ 61	$ 43	9.8 %	January 4, 2019	January 4, 2019
ACE - New Jersey (Electric)	August 21, 2018 (amended November 19, 2018)	$ 122 (a)	$ 70 (a)	9.6 %	March 13, 2019	April 1, 2019

(a) Requested and approved increases are before New Jersey sales and use tax.
Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement Increase/(Decrease)	Requested ROE	Expected Approval Timing
Pepco - Maryland (Electric)	January 15, 2019 (amended April 30, 2019)	$ 27	10.3 %	Third quarter of 2019
ComEd - Illinois (Electric)(a)	April 8, 2019	$ (6)	8.91 %	December 2019

(a) Reflects an increase of $57 million for the initial revenue requirement for 2019 and a decrease of $63 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 6.53%. See Note 4 — Regulatory Matters of the Exelon 2018 Form 10-K for additional information on ComEd's distribution formula rate filings.
Transmission Formula Rates
Pending Transmission Formula Rate (Exelon and PECO). On May 1, 2017, PECO filed a request with FERC seeking approval to update its transmission rates and change the manner in which PECO’s transmission rate is determined from a fixed rate to a formula rate. The formula rate will be updated annually to ensure that under this rate customers pay the actual costs of providing transmission services. The formula rate filing includes a requested increase of $22 million to PECO’s annual transmission revenues and a requested rate of return on common equity of 11%, inclusive of a 50 basis point adder for being a member of a regional transmission organization. PECO requested that the new transmission rate be effective as of July 2017. On June 27, 2017, FERC issued an Order accepting the filing and suspending the proposed rates until December 1, 2017, subject to refund, and set the matter for hearing and settlement judge procedures. On May 4, 2018, the Chief Administrative Law Judge terminated settlement judge procedures and designated a new presiding judge. On February 8, 2019, PECO and the active parties reached an agreement in principle to settle this case. The presiding Administrative Law Judge has since suspended the procedural schedule in order for PECO and the active parties to continue working towards finalizing a settlement. On April 15, 2019, PECO

and the active parties filed a status update with the presiding Administrative

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Law Judge requesting an additional 45 days to file a settlement. PECO cannot predict the outcome of this proceeding, or the transmission formula FERC may approve.

On May 11, 2018, pursuant to the transmission formula rate request discussed above, PECO made its first annual formula rate update, which included a revenue decrease of $6 million. The revenue decrease of $6 million included an approximately $20 million reduction as a result of the tax savings associated with the TCJA. The updated transmission rate was effective June 1, 2018, subject to refund.

Other State Regulatory Matters

New Jersey Regulatory Matters

ACE Infrastructure Investment Program Filing (Exelon, PHI and ACE). On February 28, 2018, ACE filed with the NJBPU the company’s Infrastructure Investment Program (IIP) proposing to seek recovery of a series of investments through a new rider mechanism, totaling $338 million, between 2019-2022 to provide safe and reliable service for its customers. The IIP allows for more timely recovery of investments made to modernize and enhance ACE’s electric system. On April 15, 2019, ACE entered into a settlement agreement with other parties, which allows for a recovery totaling $96 million of reliability related capital investments from July 1, 2019 through June 30, 2023. On April 18, 2019, the NJBPU approved the settlement agreement.

New Jersey Clean Energy Legislation (Exelon and ACE). On May 23, 2018, New Jersey enacted legislation that established and modified New Jersey’s clean energy and energy efficiency programs and solar and renewable energy portfolio standards. On the same day, New Jersey enacted legislation that established a ZEC program that provides compensation for nuclear plants that demonstrate to the NJBPU that they meet certain requirements, including that they make a significant contribution to air quality in the state and that their revenues are insufficient to cover their costs and risks. Electric distribution utilities in New Jersey, including ACE, must begin collecting from retail distribution customers, through a non-bypassable charge, all costs associated with the utility’s procurement of the ZECs effective April 18, 2019. See Generation Regulatory Matters below for additional information.

Other Federal Regulatory Matters

Transmission-Related Income Tax Regulatory Assets (Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE). ComEd’s, BGE’s, Pepco’s, DPL’s and ACE’s transmission formula rates currently do not provide for the pass back or recovery of income tax-related regulatory liabilities or assets, including those established upon enactment of the TCJA.

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. ComEd, Pepco, DPL and ACE had similar transmission-related income tax regulatory liabilities and assets also requiring FERC approval. On November 16, 2017, FERC issued an order rejecting BGE’s proposed revisions to its transmission formula rate to recover these transmission-related income tax regulatory assets. As a result of the FERC’s order, ComEd, BGE, Pepco, DPL and ACE took a charge to Income tax expense within their Consolidated Statements of Operations and Comprehensive Income in the fourth quarter of 2017 reducing their associated transmission-related income tax regulatory assets for the portion of the total transmission-related income tax regulatory assets that would have been previously amortized and recovered through rates. Similar regulatory assets and liabilities at PECO are not subject to the same FERC transmission rate recovery formula. See above for additional information regarding PECO's transmission formula rate filing.

On December 18, 2017, BGE filed for clarification and rehearing of FERC’s November 16, 2017 order and on February 23, 2018 (as amended on July 9, 2018), 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 BGE’s December 18, 2017 request for rehearing and clarification and ComEd's, Pepco's, DPL's and ACE's February 23, 2018 (as amended on July 9, 2018) filings, citing the lack of timeliness of the requests to recover amounts that would have been previously amortized, but indicating

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that ongoing recovery of certain transmission-related income tax regulatory assets would provide for a more accurate revenue requirement, consistent with its November 16, 2017 order.

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

If FERC ultimately rules that the future, ongoing non-TCJA amortization amounts are not recoverable, Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE would record additional charges to Income tax expense, which could be up to approximately $76 million, $51 million, $15 million, $10 million, $3 million, $5 million and $2 million, respectively, as of March 31, 2019.

Regulatory Assets and Liabilities

Regulatory assets and liabilities have not changed materially since December 31, 2018. See Note 4 — Regulatory Matters of the Exelon 2018 Form 10-K for additional information on the specific regulatory assets and liabilities.

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

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

	Exelon	ComEd[(a)]	PECO	BGE[(b)]	PHI	Pepco[(c)]	DPL[(c)]	ACE
March 31, 2019	$ 64	$ 7	$ —	$ 49	$ 8	$ 5	$ 3	$ —
December 31, 2018	$ 65	$ 8	$ —	$ 49	$ 8	$ 5	$ 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)

Illinois Regulatory Matters

Zero Emission Standard. Pursuant to FEJA, on January 25, 2018, the ICC announced that Generation’s Clinton Unit 1, Quad Cities Unit 1 and Quad Cities Unit 2 nuclear plants were selected as the winning bidders through the IPA's ZEC procurement event. Generation executed the ZEC procurement contracts with Illinois utilities, including ComEd, effective January 26, 2018 and began recognizing revenue with compensation for the sale of ZECs retroactive to the June 1, 2017 effective date of FEJA. During the three months ended March 31, 2018, Generation recognized $150 million of revenue related to ZECs generated from June 1, 2017 through December 31, 2017.

On February 14, 2017, two lawsuits were filed in the Northern District of Illinois against the IPA alleging that the state’s ZEC program violates certain provisions of the U.S. Constitution. Both lawsuits argued that the Illinois ZEC program would distort PJM's FERC-approved energy and capacity market auction system of setting wholesale prices and sought a permanent injunction preventing the implementation of the program. The lawsuits were dismissed by the district court on July 14, 2017. On September 13, 2018, the U.S. Circuit Court of Appeals for the Seventh Circuit affirmed the lower court's dismissal of both lawsuits. On January 7, 2019, plaintiffs filed a petition seeking U.S. Supreme Court review of the case which was denied on April 15, 2019.

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New Jersey Regulatory Matters

New Jersey Clean Energy Legislation. On May 23, 2018, New Jersey enacted legislation that established a ZEC program that will provide 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 November 19, 2018, NJBPU issued an order providing for the method and application process for determining the eligibility of nuclear power plants, a draft method and process for ranking and selecting eligible nuclear power plants, and the establishment of a mechanism for each regulated utility to purchase ZECs from selected nuclear power plants. On December 19, 2018, PSEG filed complete applications seeking NJBPU approval for Salem 1 and Salem 2, of which Generation owns a 42.59% ownership interest, to participate in the ZEC program. On the same day, Generation filed certain Supplemental Information with the NJBPU providing proprietary information that was requested in the application but which could not be shared with PSEG. On April 18, 2019, the NJBPU approved the award of ZECs to Salem 1 and Salem 2. See Note 8 — 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.

On October 19, 2016, a coalition of fossil-generation companies filed a complaint in federal district court against the NYPSC alleging that the ZEC program violates certain provisions of the U.S. Constitution; specifically, that the ZEC program interferes with FERC's jurisdiction over wholesale rates and that it discriminates against out of state competitors, which was dismissed by the district court on July 25, 2017. On September 27, 2018, the U.S. Court of Appeals for the Second Circuit affirmed the lower court's dismissal of the complaint against the ZEC program. On January 7, 2019, the fossil-generation companies filed a petition seeking U.S. Supreme Court review of the case which was denied on April 15, 2019.

In addition, 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. Subsequently, Generation, CENG and the NYPSC filed motions to dismiss the state court action, which were later opposed by the plaintiffs. 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. Generation, CENG and the state's answers and briefs were filed on March 30, 2018. On December 17, 2018, plaintiffs filed a reply brief introducing new arguments and new evidence. The State of New York filed a motion to strike on December 28, 2018. On January 4, 2019, Generation and CENG filed a motion to strike the new arguments and new evidence.The court must now decide whether or not to set the case for hearing.

Other legal challenges remain possible, the outcomes of which remain uncertain. See Note 8 — Early Plant Retirements for additional information related to Ginna and Nine Mile Point.

Federal Regulatory Matters

Operating License Renewals

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

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On April 27, 2018, the MDE issued its 401 Certification for Conowingo. As issued, the 401 Certification contains numerous conditions, including those relating to reduction of nutrients from upstream sources, removal of all visible trash and debris from upstream sources, and implementation of measures relating to fish passage, which could have a material, unfavorable impact in Exelon’s and Generation’s financial statements through an increase in capital expenditures and operating costs if implemented. On May 25, 2018, Generation filed complaints in federal and state court, along with a petition for reconsideration with MDE, alleging that the conditions are unfair and onerous violating MDE regulations, state, federal, and constitutional law. Generation also requested that FERC defer the issuance of the federal license while these significant state and federal law issues are pending. On February 28, 2019, Generation filed a Petition for Declaratory Order with FERC requesting that FERC issue an order declaring that MDE waived its right to issue a 401 Certification for Conowingo because it failed to timely act on Conowingo's 401 Certification application and requesting that FERC decline to include the conditions proposed by MDE in April 2018. Exelon also continues to challenge the 401 Certification through the administrative process and in state and federal court. Exelon and Generation cannot predict the final outcome or its financial impact, if any, on Exelon or Generation.

As of March 31, 2019, $38 million of direct costs associated with Conowingo licensing efforts have been capitalized.

See Note 4 — Regulatory Matters of the Exelon 2018 Form 10-K for additional information on Generation's operating license renewal efforts.

7. Impairment of Long-Lived Assets (Exelon and Generation)

Registrants evaluate long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. 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. Changes in those inputs could potentially result in material future impairments of the Registrants' long-lived assets.

Generation’s Antelope Valley, a 242 MW solar facility in Lancaster, CA, sells all of its output to Pacific Gas and Electric Company (PG&E) through a PPA. As of March 31, 2019, Generation had approximately $750 million of net long-lived assets related to Antelope Valley. As a result of the PG&E bankruptcy filing in the first quarter of 2019, Generation completed a comprehensive review of Antelope Valley's estimated undiscounted future cash flows and no impairment charge was recorded. Significant changes in assumptions such as the likelihood of the PPA being rejected as part of the bankruptcy proceedings could potentially result in future impairments of Antelope Valley’s net long-lived assets, which could be material.

Antelope Valley is a wholly owned indirect subsidiary of EGR IV, which had approximately $1,970 million of additional net long-lived assets as of March 31, 2019. EGR IV is a wholly owned indirect subsidiary of Exelon and Generation and includes Generation's interest in EGRP and other projects with non-controlling interests. To date, there have been no indicators to suggest that the carrying amount of other net long-lived assets of EGR IV may not be recoverable.

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

See Note 11 - Debt and Credit Agreements for additional information on the PG&E bankruptcy.

8. 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

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which the unit does not have capacity or other obligations, and where applicable, just prior to its next scheduled nuclear refueling outage.

Nuclear Generation

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

Assuming the continued effectiveness of the Illinois ZES, New Jersey ZEC program and the New York CES, Generation and CENG, through its ownership of Ginna and Nine Mile Point, no longer consider Clinton, Quad Cities, Salem, Ginna or Nine Mile Point to be at heightened risk for early retirement. However, to the extent the Illinois ZES, New Jersey ZEC program or the New York CES programs 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. See Note 6 — Regulatory Matters for additional information on the Illinois ZES, New Jersey ZEC program and New York CES.

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, Exelon announced that Generation will permanently cease generation operations at TMI on or about September 30, 2019. TMI is currently committed to operate through May 2019 and is licensed to operate through 2034. Generation has filed the required market and regulatory notifications to shut down the plant. PJM has subsequently notified Generation that it has not identified any reliability issues and has approved the deactivation of TMI as proposed. On April 5, 2019, Generation filed the post shutdown decommissioning activities report (PSDAR) with the NRC detailing the plans for TMI after its final shutdown.

On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at the Oyster Creek nuclear plant at the end of its current operating cycle and permanently ceased generation operations in September 2018.

As a result of these early nuclear plant retirement decisions, Exelon and Generation recognized incremental non-cash charges to earnings stemming from shortening the expected economic useful lives primarily related to accelerated depreciation of plant assets (including any ARC) and accelerated amortization of nuclear fuel, as well as operating and maintenance expenses. See Note 13 — Nuclear Decommissioning for additional information on changes to the nuclear decommissioning ARO balance. The total impact for the three months ended March 31, 2019 and 2018 are summarized in the table below.

	Three Months Ended March 31,	
Income statement expense (pre-tax)	2019	2018
Depreciation and amortization[(a)]		
Accelerated depreciation[(b)]	$74	$137
Accelerated nuclear fuel amortization	5	15
Operating and maintenance[(c)]	(83)	26
Total	$(4)	$178

(a)

Reflects incremental accelerated depreciation and amortization for TMI for the three months ended March 31, 2019. Reflects incremental accelerated depreciation for TMI and Oyster Creek for the three months ended March 31, 2018. The Oyster Creek amounts are from February 2, 2018 through March 31, 2018.

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

(c) In 2019, primarily reflects decrease to estimated decommissioning costs for TMI. See Note 13 — Nuclear Decommissioning for additional information on the first quarter 2019 TMI ARO update. In 2018, primarily reflects materials and supplies inventory reserve adjustments, employee related costs and CWIP impairments.

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Generation’s Dresden, Byron and Braidwood nuclear plants in Illinois are also showing increased signs of economic distress, which could lead to an early retirement, in a market that does not currently compensate them for their unique contribution to grid resiliency and their ability to produce large amounts of energy without carbon and air pollution. The May 2018 PJM capacity auction for the 2021-2022 planning year resulted in the largest volume of nuclear capacity ever not selected in the auction, including all of Dresden, and portions of Byron and Braidwood. Exelon continues to work with stakeholders on state policy solutions, while also advocating for broader market reforms at the regional and federal level.

Other Generation

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

On May 16, 2018, Generation made a filing with FERC to establish cost-of-service compensation and terms and conditions of service for Mystic Units 8 and 9 for the period between June 1, 2022 - May 31, 2024. On December 20, 2018, FERC issued an order accepting the cost of service agreement reflecting a number of adjustments to the annual fixed revenue requirement and allowing for recovery of a substantial portion of the costs associated with the Everett Marine Terminal. Those adjustments were reflected in a compliance filing filed March 1, 2019. In the December 20, 2018 order, FERC also directed a paper hearing on ROE using a new methodology. Initial briefs in the ROE proceeding were filed on April 19, 2019 and reply briefs are due on July 18, 2019. On January 4, 2019, Generation notified ISO-NE that it will participate in the Forward Capacity Market auction for the 2022 - 2023 capacity commitment period. In addition, on January 22, 2019, Exelon and several other parties filed requests for rehearing of certain findings of the December 20, 2018 order, which does not alter Generation's commitment to participate in the Forward Capacity Auction for the 2022-2023 capacity commitment period.

On March 25, 2019, ISO-NE filed the Inventoried Energy Program, which is intended to provide an interim fuel security program pending conclusion of the stakeholder process to develop a long-term, market-based solution to address fuel security. Exelon filed comments on the Inventoried Energy Program proposal on April 15, 2019. FERC has ordered ISO-NE to file the long-term, market-based fuel security rules by October 15, 2019.

The following table provides the balance sheet amounts as of March 31, 2019 for Exelon's and Generation’s significant assets and liabilities associated with the Mystic Units 8 and 9 and Everett Marine Terminal assets that would potentially be impacted by a decision to permanently cease generation operations in the absence of long-term market rule changes.

	March 31, 2019
Asset Balances	
Materials and supplies inventory	$ 30
Fuel inventory	22
Completed plant, net	900
Construction work in progress	2
Liability Balances	
Asset retirement obligation	(1)

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

Fair Value of Financial Liabilities Recorded at Amortized Cost

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of March 31, 2019 and December 31, 2018:

Exelon

	March 31, 2019				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$1,254	$—	$1,254	$ —	$1,254
Long-term debt (including amounts due within one year)[(a)]	35,468	—	35,066	2,188	37,254
Long-term debt to financing trusts[(b)]	390	—	—	411	411
SNF obligation	1,178	—	989	—	989

	December 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$714	$—	$714	$ —	$714
Long-term debt (including amounts due within one year)[(a)]	35,424	—	33,711	2,158	35,869
Long-term debt to financing trusts[(b)]	390	—	—	400	400
SNF obligation	1,171	—	949	—	949

Generation

	March 31, 2019				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[(a)]	$8,747	$—	$7,641	$1,443	$9,084
SNF obligation	1,178	—	989	—	989

	December 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[(a)]	$8,793	$—	$7,467	$1,443	$8,910
SNF obligation	1,171	—	949	—	949

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ComEd

	March 31, 2019				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$322	$—	$322	$—	$322
Long-term debt (including amounts due within one year)[a]	8,194	—	8,855	—	8,855
Long-term debt to financing trusts[b]	205	—	—	215	215

	December 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$8,101	$—	$8,390	$—	$8,390
Long-term debt to financing trusts[b]	205	—	—	209	209

PECO

	March 31, 2019				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$3,084	$—	$3,295	$50	$3,345
Long-term debt to financing trusts[b]	184	—	—	196	196

	December 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$3,084	$—	$3,157	$50	$3,207
Long-term debt to financing trusts[b]	184	—	—	191	191

BGE

	March 31, 2019				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$106	$—	$106	$—	$106
Long-term debt (including amounts due within one year)[a]	2,876	—	3,051	—	3,051

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

	December 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$35	$—	$ 35	$ —	$ 35
Long-term debt (including amounts due within one year)[(a)]	2,876	—	2,950	—	2,950

PHI

	March 31, 2019				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$326	$—	$326	$ —	$326
Long-term debt (including amounts due within one year)[(a)]	6,244	—	5,608	695	6,303
	December 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$179	$—	$179	$ —	$179
Long-term debt (including amounts due within one year)[(a)]	6,259	—	5,436	665	6,101

Pepco

	March 31, 2019				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$105	$—	$105	$ —	$105
Long-term debt (including amounts due within one year)[(a)]	2,720	—	3,000	208	3,208
	December 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$40	$—	$ 40	$ —	$ 40
Long-term debt (including amounts due within one year)[(a)]	2,719	—	2,901	196	3,097

DPL

	March 31, 2019				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$5	$—	$ 5	$ —	$ 5
Long-term debt (including amounts due within one year)[(a)]	1,495	—	1,345	204	1,549

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

	December 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[(a)]	$1,494	$—	$1,303	$193	$1,496

ACE

	March 31, 2019				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$216	$—	$216	$ —	$216
Long-term debt (including amounts due within one year)[(a)]	1,184	—	1,004	283	1,287

	December 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$139	$—	$139	$ —	$139
Long-term debt (including amounts due within one year)[(a)]	1,188	—	987	275	1,262

(a) Includes unamortized debt issuance costs which are not fair valued of $216 million, $49 million, $67 million, $22 million, $18 million, $14 million, $33 million, $12 million and $6 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, as of March 31, 2019. Includes unamortized debt issuance costs which are not fair valued of $216 million, $51 million, $63 million, $23 million, $18 million, $14 million, $34 million, $12 million and $7 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, as of December 31, 2018.

(b) Includes unamortized debt issuance costs which are not fair valued of $1 million and $1 million for Exelon and ComEd, respectively, as of March 31, 2019. Includes unamortized debt issuance costs which are not fair valued of less than $1 million and $1 million for Exelon and ComEd, respectively, as of December 31, 2018.

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. 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.

Generation and Exelon

In accordance with the applicable guidance on fair value measurement, certain investments that are measured at fair value using the NAV per share as a practical expedient are no longer classified within the fair value hierarchy and are included under "Not subject to leveling" in the table below.

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

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

	Generation					Exelon				
As of March 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)]	$370	$ —	$ —	$ —	$370	$817	$ —	$ —	$ —	$817
NDT fund investments										
Cash equivalents[(b)]	369	74	—	—	443	369	74	—	—	443
Equities	3,060	1,753	1	1,545	6,359	3,060	1,753	1	1,545	6,359
Fixed income										
Corporate debt	—	1,545	236	1	1,782	—	1,545	236	1	1,782
U.S. Treasury and agencies	2,033	112	—	—	2,145	2,033	112	—	—	2,145
Foreign governments	—	43	—	—	43	—	43	—	—	43
State and municipal debt	—	110	—	—	110	—	110	—	—	110
Other[(c)]	—	26	—	935	961	—	26	—	935	961
Fixed income subtotal	2,033	1,836	236	936	5,041	2,033	1,836	236	936	5,041
Middle market lending	—	—	303	406	709	—	—	303	406	709
Private equity	—	—	—	352	352	—	—	—	352	352
Real estate	—	—	—	535	535	—	—	—	535	535
NDT fund investments subtotal[(d)]	5,462	3,663	540	3,774	13,439	5,462	3,663	540	3,774	13,439
Rabbi trust investments										
Cash equivalents	4	—	—	—	4	47	—	—	—	47
Mutual funds	25	—	—	—	25	74	—	—	—	74
Fixed income	—	—	—	—	—	—	14	—	—	14
Life insurance contracts	—	23	—	—	23	—	71	39	—	110
Rabbi trust investments subtotal[(e)]	29	23	—	—	52	121	85	39	—	245
Commodity derivative assets										
Economic hedges	273	2,164	1,442	—	3,879	273	2,164	1,442	—	3,879
Proprietary trading	—	74	104	—	178	—	74	104	—	178
Effect of netting and allocation of collateral[(f)(g)]	(294)	(1,836)	(820)	—	(2,950)	(294)	(1,836)	(820)	—	(2,950)
Commodity derivative assets subtotal	(21)	402	726	—	1,107	(21)	402	726	—	1,107
Interest rate and foreign currency derivative assets										
Economic hedges	—	4	—	—	4	—	4	—	—	4
Effect of netting and allocation of collateral	—	(5)	—	—	(5)	—	(5)	—	—	(5)
Interest rate and foreign currency derivative assets subtotal	—	(1)	—	—	(1)	—	(1)	—	—	(1)
Other investments	—	—	42	—	42	—	—	42	—	42
Total assets	5,840	4,087	1,308	3,774	15,009	6,379	4,149	1,347	3,774	15,649

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

	Generation					Exelon				
As of March 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	(350)	(2,339)	(1,164)	—	(3,853)	(350)	(2,339)	(1,404)	—	(4,093)
Proprietary trading	—	(79)	(40)	—	(119)	—	(79)	(40)	—	(119)
Effect of netting and allocation of collateral[(f)(g)]	346	2,119	977	—	3,442	346	2,119	977	—	3,442
	(4)	(299)	(227)	—	(530)	(4)	(299)	(467)	—	(770)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments	—	—	—	—	—	—	(2)	—	—	(2)
Economic hedges	—	(12)	—	—	(12)	—	(12)	—	—	(12)
Effect of netting and allocation of collateral	—	5	—	—	5	—	5	—	—	5
Interest rate and foreign currency derivative liabilities subtotal	—	(7)	—	—	(7)	—	(9)	—	—	(9)
Deferred compensation obligation	—	(36)	—	—	(36)	—	(140)	—	—	(140)
Total liabilities	(4)	(342)	(227)	—	(573)	(4)	(448)	(467)	—	(919)
Total net assets	$5,836	$3,745	$1,081	$3,774	$14,436	$6,375	$3,701	$880	$3,774	$14,730

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

	Generation					Exelon				
As of December 31, 2018	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)]	$581	$ —	$ —	$ —	$581	$1,243	$ —	$ —	$ —	$1,243
NDT fund investments										
Cash equivalents[(b)]	252	86	—	—	338	252	86	—	—	338
Equities	2,918	1,591	—	1,381	5,890	2,918	1,591	—	1,381	5,890
Fixed income										
Corporate debt	—	1,593	230	—	1,823	—	1,593	230	—	1,823
U.S. Treasury and agencies	2,081	99	—	—	2,180	2,081	99	—	—	2,180
Foreign governments	—	50	—	—	50	—	50	—	—	50
State and municipal debt	—	149	—	—	149	—	149	—	—	149
Other[(c)]	—	30	—	846	876	—	30	—	846	876
Fixed income subtotal	2,081	1,921	230	846	5,078	2,081	1,921	230	846	5,078
Middle market lending	—	—	313	367	680	—	—	313	367	680
Private equity	—	—	—	329	329	—	—	—	329	329
Real estate	—	—	—	510	510	—	—	—	510	510
NDT fund investments subtotal[(d)]	5,251	3,598	543	3,433	12,825	5,251	3,598	543	3,433	12,825
Rabbi trust investments										
Cash equivalents	5	—	—	—	5	48	—	—	—	48
Mutual funds	24	—	—	—	24	72	—	—	—	72
Fixed income	—	—	—	—	—	—	15	—	—	15
Life insurance contracts	—	22	—	—	22	—	70	38	—	108
Rabbi trust investments subtotal[(e)]	29	22	—	—	51	120	85	38	—	243
Commodity derivative assets										
Economic hedges	541	2,760	1,470	—	4,771	541	2,760	1,470	—	4,771
Proprietary trading	—	69	77	—	146	—	69	77	—	146
Effect of netting and allocation of collateral[(f)(g)]	(582)	(2,357)	(732)	—	(3,671)	(582)	(2,357)	(732)	—	(3,671)
Commodity derivative assets subtotal	(41)	472	815	—	1,246	(41)	472	815	—	1,246
Interest rate and foreign currency derivative assets										
Economic hedges	—	13	—	—	13	—	13	—	—	13
Effect of netting and allocation of collateral	—	(3)	—	—	(3)	—	(3)	—	—	(3)
Interest rate and foreign currency derivative assets subtotal	—	10	—	—	10	—	10	—	—	10
Other investments	—	—	42	—	42	—	—	42	—	42
Total assets	5,820	4,102	1,400	3,433	14,755	6,573	4,165	1,438	3,433	15,609

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

As of December 31, 2018	Generation Level 1	Generation Level 2	Generation Level 3	Generation Not subject to leveling	Generation Total	Exelon Level 1	Exelon Level 2	Exelon Level 3	Exelon Not subject to leveling	Exelon Total
Liabilities										
Commodity derivative liabilities										
Economic hedges	(642)	(2,963)	(1,027)	—	(4,632)	(642)	(2,963)	(1,276)	—	(4,881)
Proprietary trading	—	(73)	(21)	—	(94)	—	(73)	(21)	—	(94)
Effect of netting and allocation of collateral[(f)(g)]	639	2,581	808	—	4,028	639	2,581	808	—	4,028
Commodity derivative liabilities subtotal	(3)	(455)	(240)	—	(698)	(3)	(455)	(489)	—	(947)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments	—	—	—	—	—	—	(4)	—	—	(4)
Economic hedges	—	(6)	—	—	(6)	—	(6)	—	—	(6)
Effect of netting and allocation of collateral	—	3	—	—	3	—	3	—	—	3
Interest rate and foreign currency derivative liabilities subtotal	—	(3)	—	—	(3)	—	(7)	—	—	(7)
Deferred compensation obligation	—	(35)	—	—	(35)	—	(137)	—	—	(137)
Total liabilities	(3)	(493)	(240)	—	(736)	(3)	(599)	(489)	—	(1,091)
Total net assets	$5,817	$3,609	$1,160	$3,433	$14,019	$6,570	$3,566	$949	$3,433	$14,518

(a) Generation excludes cash of $270 million and $283 million at March 31, 2019 and December 31, 2018 and restricted cash of $36 million and $39 million at March 31, 2019 and December 31, 2018. Exelon excludes cash of $426 million and $458 million at March 31, 2019 and December 31, 2018 and restricted cash of $71 million and $80 million at March 31, 2019 and December 31, 2018 and includes long-term restricted cash of $211 million and $185 million at March 31, 2019 and December 31, 2018, which is reported in Other deferred debits in the Consolidated Balance Sheets.

(b) Includes $43 million and $50 million of cash received from outstanding repurchase agreements at March 31, 2019 and December 31, 2018, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (d) below.

(c) Includes derivative instruments of $7 million and $44 million, which have a total notional amount of $1,223 million and $1,432 million at March 31, 2019 and December 31, 2018, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of Exelon and Generation's exposure to credit or market loss.

(d) Excludes net liabilities of $94 million and $130 million at March 31, 2019 and December 31, 2018, 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) The amount of unrealized gains/(losses) at Generation totaled less than $1 million for the three months ended March 31, 2019 and March 31, 2018, respectively. The amount of unrealized gains/(losses) at Exelon totaled $1 million for the three months ended March 31, 2019 and March 31, 2018, respectively.

(f) Collateral posted/(received) from counterparties totaled $52 million, $283 million and $157 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of March 31, 2019. Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled $57 million, $224 million and $76 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2018.

(g) Of the collateral posted/(received), $(33) million and $(94) million represents variation margin on the exchanges as of March 31, 2019 and December 31, 2018, respectively.

Exelon and Generation hold investments without readily determinable fair values with carrying amounts of $71 million as of March 31, 2019. Changes were immaterial in fair value, cumulative adjustments and impairments for the three months ended March 31, 2019.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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ComEd, PECO and BGE

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

	ComEd				PECO				BGE			
As of March 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]	$194	$ —	$—	$194	$16	$ —	$ —	$16	$3	$ —	$ —	$3
Rabbi trust investments												
Mutual funds	—	—	—	—	7	—	—	7	6	—	—	6
Life insurance contracts	—	—	—	—	—	10	—	10	—	—	—	—
Rabbi trust investments subtotal[b]	—	—	—	—	7	10	—	17	6	—	—	6
Total assets	194	—	—	194	23	10	—	33	9	—	—	9
Liabilities												
Deferred compensation obligation	—	(7)	—	(7)	—	(10)	—	(10)	—	(5)	—	(5)
Mark-to-market derivative liabilities[c]	—	—	(240)	(240)	—	—	—	—	—	—	—	—
Total liabilities	—	(7)	(240)	(247)	—	(10)	—	(10)	—	(5)	—	(5)
Total net assets (liabilities)	$194	$ (7)	$(240)	$(53)	$23	$ —	$ —	$23	$9	$ (5)	$ —	$4

	ComEd				PECO				BGE			
As of December 31, 2018	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]	$209	$ —	$—	$209	$111	$ —	$ —	$111	$4	$ —	$ —	$4
Rabbi trust investments												
Mutual funds	—	—	—	—	7	—	—	7	6	—	—	6
Life insurance contracts	—	—	—	—	—	10	—	10	—	—	—	—
Rabbi trust investments subtotal[b]	—	—	—	—	7	10	—	17	6	—	—	6
Total assets	209	—	—	209	118	10	—	128	10	—	—	10
Liabilities												
Deferred compensation obligation	—	(6)	—	(6)	—	(10)	—	(10)	—	(5)	—	(5)
Mark-to-market derivative liabilities[c]	—	—	(249)	(249)	—	—	—	—	—	—	—	—
Total liabilities	—	(6)	(249)	(255)	—	(10)	—	(10)	—	(5)	—	(5)
Total net assets (liabilities)	$209	$ (6)	$(249)	$(46)	$118	$ —	$ —	$118	$10	$ (5)	$ —	$5

(a) ComEd excludes cash of $69 million and $93 million at March 31, 2019 and December 31, 2018 and restricted cash of $15 million and $28 million at March 31, 2019 and December 31, 2018 and includes long-term restricted cash of $193 million and $166 million at March 31, 2019 and December 31, 2018, which is reported in Other deferred debits in the Consolidated Balance Sheets. PECO excludes cash of $31 million and $24 million at March 31, 2019 and December 31, 2018. BGE excludes cash of $12 million and $7 million at March 31, 2019 and December 31, 2018 and restricted cash of $1 million and $2 million at March 31, 2019 and December 31, 2018.

(b) The amount of unrealized gains/(losses) at ComEd, PECO and BGE totaled less than $1 million for the three months ended March 31, 2019 and March 31, 2018.

(c) The Level 3 balance consists of the current and noncurrent liability of $27 million and $213 million, respectively, at March 31, 2019, and $26 million and $223 million, respectively, at December 31, 2018, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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PHI, Pepco, DPL and ACE
The following tables present assets and liabilities measured and recorded at fair value in PHI's, Pepco's, DPL's and ACE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2019 and December 31, 2018:

	As of March 31, 2019				As of December 31, 2018			
PHI	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents[(a)]	$63	$ —	$ —	$63	$147	$ —	$ —	$147
Rabbi trust investments								
Cash equivalents	42	—	—	42	42	—	—	42
Mutual funds	14	—	—	14	13	—	—	13
Fixed income	—	14	—	14	—	15	—	15
Life insurance contracts	—	22	39	61	—	22	38	60
Rabbi trust investments subtotal[(b)]	56	36	39	131	55	37	38	130
Total assets	119	36	39	194	202	37	38	277
Liabilities								
Deferred compensation obligation	—	(20)	—	(20)	—	(21)	—	(21)
Total liabilities	—	(20)	—	(20)	—	(21)	—	(21)
Total net assets	$119	$ 16	$ 39	$174	$202	$ 16	$ 38	$256

	Pepco				DPL				ACE			
As of March 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)]	$35	$ —	$ —	$35	$2	$ —	$ —	$ 2	$21	$ —	$ —	$ 21
Rabbi trust investments												
Cash equivalents	42	—	—	42	—	—	—	—	—	—	—	—
Fixed income	—	4	—	4	—	—	—	—	—	—	—	—
Life insurance contracts	—	22	38	60	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal[(b)]	42	26	38	106	—	—	—	—	—	—	—	—
Total assets	77	26	38	141	2	—	—	2	21	—	—	21
Liabilities												
Deferred compensation obligation	—	(3)	—	(3)	—	(1)	—	(1)	—	—	—	—
Total liabilities	—	(3)	—	(3)	—	(1)	—	(1)	—	—	—	—
Total net assets (liabilities)	$77	$ 23	$ 38	$138	$2	$ (1)	$ —	$ 1	$21	$ —	$ —	$ 21

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

	Pepco				DPL				ACE			
As of December 31, 2018	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)]	$38	$ —	$ —	$38	$16	$ —	$ —	$16	$23	$ —	$ —	$ 23
Rabbi trust investments												
Cash equivalents	41	—	—	41	—	—	—	—	—	—	—	—
Fixed income	—	5	—	5	—	—	—	—	—	—	—	—
Life insurance contracts	—	22	37	59	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal[(b)]	41	27	37	105	—	—	—	—	—	—	—	—
Total assets	79	27	37	143	16	—	—	16	23	—	—	23
Liabilities												
Deferred compensation obligation	—	(3)	—	(3)	—	(1)	—	(1)	—	—	—	—
Total liabilities	—	(3)	—	(3)	—	(1)	—	(1)	—	—	—	—
Total net assets (liabilities)	$79	$ 24	$ 37	$140	$16	$ (1)	$ —	$15	$23	$ —	$ —	$ 23

(a) PHI excludes cash of $29 million and $39 million at March 31, 2019 and December 31, 2018, respectively, and includes long-term restricted cash of $19 million at both March 31, 2019 and December 31, 2018, which is reported in Other deferred debits in the Consolidated Balance Sheets. Pepco excludes cash of $11 million and $15 million at March 31, 2019 and December 31, 2018, respectively. DPL excludes cash of $6 million and $8 million at March 31, 2019 and December 31, 2018, respectively. ACE excludes cash of $7 million at both March 31, 2019 and December 31, 2018, and includes long-term restricted cash of $19 million at both March 31, 2019 and December 31, 2018, which is reported in Other deferred debits in the Consolidated Balance Sheets.

(b) The amount of unrealized gains/(losses) at PHI totaled less than $1 million for both the three months ended March 31, 2019 and 2018. The amount of unrealized gains/(losses) at Pepco totaled less than $1 million for both the three months ended March 31, 2019 and 2018.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2019 and 2018:

Three Months Ended March 31, 2019	Generation NDT Fund Investments	Mark-to-Market Derivatives	Other Investments	Total Generation	ComEd Mark-to-Market Derivatives	PHI Life Insurance Contracts	Eliminated in Consolidation[c]	Exelon Total
Balance as of December 31, 2018	$543	$ 575	$ 42	$ 1,160	$ (249)	$ 38	$ —	$949
Total realized / unrealized gains (losses)								
Included in net income	2	(231) [a]	—	(229)	—	1	—	(228)
Included in noncurrent payables to affiliates	11	—	—	11	—	—	(11)	—
Included in regulatory assets/liabilities	—	—	—	—	9 [b]	—	11	20
Change in collateral	—	81	—	81	—	—	—	81
Purchases, sales, issuances and settlements								
Purchases	1	57	—	58	—	—	—	58
Sales	—	—	—	—	—	—	—	—
Settlements	(17)	—	—	(17)	—	—	—	(17)
Transfers into Level 3	—	— [d]	—	—	—	—	—	—
Transfers out of Level 3	—	17 [d]	—	17	—	—	—	17
Balance at March 31, 2019	$540	$ 499	$ 42	$ 1,081	$ (240)	$ 39	$ —	$880
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of March 31, 2019	$2	$ (151)	$ —	$ (149)	$ —	$ 1	$ —	$(148)

Three Months Ended March 31, 2018	Generation NDT Fund Investments	Mark-to-Market Derivatives	Other Investments	Total Generation	ComEd Mark-to-Market Derivatives	PHI Life Insurance Contracts	Eliminated in Consolidation[c]	Exelon Total
Balance as of December 31, 2017	$648	$ 552	$ 37	$ 1,237	$ (256)	$ 22	$ —	$1,003
Total realized / unrealized gains (losses)								
Included in net income	—	184 [a]	1	185	—	1	—	186
Included in noncurrent payables to affiliates	7	—	—	7	—	—	(7)	—
Included in regulatory assets	—	—	—	—	(11) [b]	—	7	(4)
Change in collateral	—	105	—	105	—	—	—	105
Purchases, sales, issuances and settlements								
Purchases	2	88	—	90	—	—	—	90
Sales	—	(3)	—	(3)	—	—	—	(3)
Issuances	—	—	—	—	—	—	—	—

Settlements	(48)	—	—	(48)	—	—	—	(48)
Transfers into Level 3	—	(8) [d]	—	(8)	—	—	—	(8)
Transfers out of Level 3	—	— [d]	(2)	(2)	—	—	—	(2)
Balance as of March 31, 2018	$609	$ 918	$ 36	$ 1,563	$ (267)	$ 23	$ —	$1,319
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of March 31, 2018	$—	$ 256	$ 1	$ 257	$ —	$ 1	$ —	$258

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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(a) Includes a reduction for the reclassification of $80 million and $72 million of realized gains due to the settlement of derivative contracts for the three months ended March 31, 2019 and 2018, respectively.
(b) Includes $14 million of decreases in fair value and an increase for realized losses due to settlements of $5 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2019. Includes $17 million of increases in fair value and an increase for realized losses due to settlements of $6 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2018.
(c) The amounts represented are life insurance contracts at Pepco.
(d) Transfers into and out of Level 3 generally occur when the contract tenor becomes less and more observable respectively, primarily due to changes in market liquidity or assumptions for certain commodity contracts.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2019 and 2018:

	Generation			PHI	Exelon			
	Operating Revenues	Purchased Power and Fuel	Other, net	Operating and Maintenance	Operating Revenues	Purchased Power and Fuel	Operating and Maintenance	Other, net
Total gains (losses) included in net income for the three months ended March 31, 2019	$(128)	$(103)	$ 2	$ 1	$(128)	$(103)	$ 1	$ 2
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended March 31, 2019	(91)	(60)	2	1	(91)	(60)	1	2

	Generation			PHI	Exelon			
	Operating Revenues	Purchased Power and Fuel	Other, net	Operating and Maintenance	Operating Revenues	Purchased Power and Fuel	Operating and Maintenance	Other, net
Total gains (losses) included in net income for the three months ended March 31, 2018	$335	$(151)	$ 1	$ 1	$335	$(151)	$ 1	$ 1
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended March 31, 2018	309	(53)	1	1	309	(53)	1	1

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents (All Registrants). The Registrants' cash equivalents include investments with original maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

NDT Fund Investments (Exelon and Generation). The trust fund investments have been established to satisfy Generation's and CENG's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds and mutual funds, which are included in Equities and Fixed Income. Generation's and CENG's NDT fund investments policies outline investment guidelines for the trusts and limit the trust funds' exposures to investments in highly illiquid markets and other alternative investments. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are generally obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds which are based on quoted prices in active markets are categorized in Level 1. Certain equity securities have been categorized as Level 2 because they are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The fair values of private placement fixed income securities, which are included in Corporate debt, are determined using a third-party valuation that contains significant unobservable inputs and are categorized in Level 3.

Equity and fixed income commingled funds and mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives such as holding short-term fixed income securities or tracking the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For commingled funds and mutual funds, which are not publicly quoted, the funds are valued using NAV as a practical expedient for fair value, which is primarily derived from the quoted prices in active markets on the underlying securities, and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly with 30 or less days of notice and without further restrictions.

Derivative instruments consisting primarily of futures and interest rate swaps to manage risk are recorded at fair value. Over the counter derivatives are valued daily based on quoted prices in active markets and trade in open markets and have been categorized as Level 1. Derivative instruments other than over the counter derivatives are valued based on external price data of comparable securities and have been categorized as Level 2.

Middle market lending are investments in loans or managed funds which lend to private companies. Generation elected the fair value option for its investments in certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models and income models. Investments in loans are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Managed funds are valued using NAV or its equivalent as a practical expedient, and therefore, are not classified within the fair value hierarchy. Investments in middle market lending 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. The fair value of private equity and real estate investments is determined using NAV or its equivalent as a practical expedient, and therefore, are not classified within the fair value hierarchy. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date. 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.

As of March 31, 2019, Exelon and Generation have outstanding commitments to invest in fixed income, middle market lending, private equity and real estate investments of approximately $127 million, $179 million, $301 million, and $268 million, respectively. These commitments will be funded by Generation's existing NDT funds.

Concentrations of Credit Risk. Generation evaluated its NDT portfolios for the existence of significant concentrations of credit risk as of March 31, 2019. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of March 31, 2019, there were no significant concentrations (generally defined as greater than 10 percent) of risk in Generation's NDT assets.

See Note 13 — Nuclear Decommissioning for additional information on the NDT fund investments.

Rabbi Trust Investments (Exelon, Generation, PECO, BGE, PHI, and Pepco). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The Rabbi trusts assets are included in investments in the Registrants' Consolidated Balance Sheets and consist primarily of money market funds, mutual funds, fixed income securities and life insurance policies. The mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Money market funds and mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices. The fair values of fixed income securities are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The life insurance policies are valued using the cash surrender value of the policies, net of loans against those policies, which is provided by a third-party. Certain life insurance policies, which consist primarily of mutual funds that are priced based on observable market data, have been categorized as Level 2 because the life insurance policies can be liquidated at the reporting date for the value of the underlying assets. Life insurance policies that are valued using unobservable inputs have been categorized as Level 3.

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

Exelon may utilize fixed-to-floating interest rate swaps as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 10 — Derivative Financial Instruments for additional information on mark-to-market derivatives.

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

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The value of certain employment agreement obligations (which are included with the Deferred Compensation Obligation in the tables above) are based on a known and certain stream of payments to be made over time and are categorized as Level 2 within the fair value hierarchy.

Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd, PHI, Pepco, DPL and ACE)

NDT Fund Investments (Exelon and Generation). For middle market lending and certain corporate debt securities investments, the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on discounting the forecasted cash flows, market-based comparable data, credit and liquidity factors, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied for factors such as size, marketability, credit risk and relative performance.

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Therefore, Generation has not disclosed such inputs.

Rabbi Trust Investments - Life insurance contracts (Exelon, PHI, and Pepco). For life insurance policies categorized as Level 3, the fair value is determined based on the cash surrender value of the policy, which contains unobservable inputs and assumptions. Because Exelon relies on its third-party insurance provider to develop the inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Exelon. Therefore, Exelon has not disclosed such inputs.

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

Disclosed below is detail surrounding the Registrants' significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and other attributes. Generation's Level 3 balance generally consists of forward sales and purchases of power and natural gas and certain transmission congestion contracts. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price varies generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is

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generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $2.52 and $0.46 for power and natural gas, respectively. Many of the commodity derivatives are short-term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3.
On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 10 —Derivative Financial Instruments for additional information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.
The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade	Fair Value at March 31, 2019	Valuation Technique	Unobservable Input	Range	
Mark-to-market derivatives — Economic Hedges (Exelon and Generation)[(a)(b)]	$ 278	Discounted Cash Flow	Forward power price	$9	- $164
			Forward gas price	$1.76	- $11.63
		Option Model	Volatility percentage	10%	- 334%
Mark-to-market derivatives — Proprietary trading (Exelon and Generation)[(a)(b)]	$ 64	Discounted Cash Flow	Forward power price	$9	- $162
Mark-to-market derivatives (Exelon and ComEd)	$ (240)	Discounted Cash Flow	Forward heat rate[(c)]	10x	- 11x
			Marketability reserve	4%	- 8%
			Renewable factor	85%	- 120%

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Type of trade	Fair Value at December 31, 2018	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives — Economic Hedges (Exelon and Generation)[a][b]	$ 443	Discounted Cash Flow	Forward power price	$12 - $174
			Forward gas price	$0.78 - $12.38
		Option Model	Volatility percentage	10% - 277%
Mark-to-market derivatives — Proprietary trading (Exelon and Generation)[a][b]	$ 56	Discounted Cash Flow	Forward power price	$14 - $174
Mark-to-market derivatives (Exelon and ComEd)	$ (249)	Discounted Cash Flow	Forward heat rate[c]	10x - 11x
			Marketability reserve	4% - 8%
			Renewable factor	86% - 120%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) The fair values do not include cash collateral posted on level three positions of $157 million and $76 million as of March 31, 2019 and December 31, 2018, 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.

10. 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.

Commodity Price Risk (All Registrants)

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. 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.

Derivative authoritative guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings immediately. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedges and fair value hedges. For Generation, all derivative economic hedges related to commodities are recorded at fair value through earnings for the consolidated company, referred to as economic hedges in the following tables. 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.

Fair value authoritative guidance and disclosures 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 Sheet. 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. Generation's use of cash collateral is generally unrestricted, unless Generation is downgraded below investment grade (i.e., to BB+ or Ba1). In the table below, 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 column. As of March 31, 2019, $6 million of cash collateral held, and as of December 31, 2018, $2 million of cash collateral posted and an additional $12 million of cash collateral posted with ComEd, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives, were associated with accrual positions, or had no positions to offset as of the balance sheet date. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

ComEd's use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade (i.e., to BB+ or Ba1).

Cash collateral held by PECO and BGE must be deposited in an unaffiliated major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

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The following table provides a summary of the derivative fair value balances recorded by the Registrants as of March 31, 2019:

	Generation				ComEd	Exelon
Derivatives	Economic Hedges	Proprietary Trading	Collateral and Netting[(a)(d)]	Subtotal[(b)]	Economic Hedges[(c)]	Total Derivatives
Mark-to-market derivative assets (current assets)	$2,691	$ 118	$ (2,156)	$ 653	$ —	$ 653
Mark-to-market derivative assets (noncurrent assets)	1,188	60	(794)	454	—	454
Total mark-to-market derivative assets	3,879	178	(2,950)	1,107	—	1,107
Mark-to-market derivative liabilities (current liabilities)	(2,711)	(89)	2,485	(315)	(27)	(342)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,142)	(30)	957	(215)	(213)	(428)
Total mark-to-market derivative liabilities	(3,853)	(119)	3,442	(530)	(240)	(770)
Total mark-to-market derivative net assets (liabilities)	$26	$ 59	$ 492	$ 577	$ (240)	$ 337

(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 are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $152 million and $63 million, respectively, and current and noncurrent liabilities are shown net of collateral of $177 million and $100 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $492 million at March 31, 2019.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

(d) Of the collateral posted/(received), $(33) million represents variation margin on the exchanges.

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The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2018:

Description	Generation				ComEd	Exelon
	Economic Hedges	Proprietary Trading	Collateral and Netting[(a)(d)]	Subtotal[(b)]	Economic Hedges[(c)]	Total Derivatives
Mark-to-market derivative assets (current assets)	$3,505	$ 105	$ (2,809)	$ 801	$ —	$ 801
Mark-to-market derivative assets (noncurrent assets)	1,266	41	(862)	445	—	445
Total mark-to-market derivative assets	4,771	146	(3,671)	1,246	—	1,246
Mark-to-market derivative liabilities (current liabilities)	(3,429)	(74)	3,056	(447)	(26)	(473)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,203)	(20)	972	(251)	(223)	(474)
Total mark-to-market derivative liabilities	(4,632)	(94)	4,028	(698)	(249)	(947)
Total mark-to-market derivative net assets (liabilities)	$139	$ 52	$ 357	$ 548	$ (249)	$ 299

(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, and letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $121 million and $51 million, respectively, and current and noncurrent liabilities are shown net of collateral of $125 million and $60 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $357 million at December 31, 2018.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

(d) Of the collateral posted/(received), $(94) million represents variation margin on the exchanges.

Economic Hedges (Commodity Price Risk)

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. For the three months ended March 31, 2019 and 2018, Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses) which are also located in the "Net fair value changes related to derivatives" in the Consolidated Statements of Cash Flows.

	Three Months Ended March 31,	
	2019	2018
Income Statement Location	Gain (Loss)	
Operating revenues	$(50)	$(100)
Purchased power and fuel	30	(167)
Total Exelon and Generation	$(20)	$(267)

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In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation’s owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of March 31, 2019, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York and ERCOT reportable segments is 90%-93%, 64%-67% and 38%-41% for 2019, 2020 and 2021, respectively.

On December 17, 2010, ComEd executed several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts in its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 4 — Regulatory Matters of the Exelon 2018 Form 10-K for additional information.

PECO’s natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches to achieve system supply reliability at the least cost. PECO’s reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO’s natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2018 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2018 and previous PGC settlements, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO’s gas-hedging program is designed to cover about 20% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO’s results of operations and financial position as natural gas costs are fully recovered from customers under the PGC.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. BGE’s commodity price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of BGE’s full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other BGE full requirements contracts are not derivatives.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE’s actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE’s actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the MBR mechanism. BGE also ensures it has sufficient pipeline transportation capacity to meet customer requirements. BGE’s natural gas supply and asset management agreements qualify for the NPNS scope exception and result in physical delivery.

Pepco has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and DCPSC. The SOS rates charged recover Pepco's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for residential and commercial rate classes. Pepco’s commodity price risk related to electric supply procurement is limited. Pepco locks in fixed prices for its SOS requirements through full requirements contracts. Certain of Pepco’s full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other Pepco full requirements contracts are not derivatives.

DPL has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and the DPSC. The SOS rates charged recover DPL's wholesale power supply costs. In Delaware, DPL is also entitled to recover a Reasonable Allowance for Retail Margin (RARM). The RARM includes

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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a fixed annual margin of approximately $2.75 million, plus an incremental cost component and a cash working capital allowance. In Maryland, DPL charges an administrative fee intended to allow it to recover its administrative costs. DPL locks in fixed prices for its SOS requirements through full requirements contracts. DPL’s commodity price risk related to electric supply procurement is limited. Certain of DPL’s full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

DPL provides natural gas to its customers under an Annual GCR mechanism approved by the DPSC. Under this mechanism, DPL’s Annual GCR Filing establishes a future GCR for firm bundled sales customers by using a forecast of demand and commodity costs. The actual costs are trued up against forecasts on a monthly basis and any shortfall or excess is carried forward as a recovery balance in the next GCR filing. The demand portion of the GCR is based upon DPL’s firm transportation and storage contracts. DPL has firm deliverability of swing and seasonal storage, a liquefied natural gas facility and firm transportation capacity to meet customer demand and provide a reserve margin. The commodity portion of the GCR includes a commission approved hedging program which is intended to reduce gas commodity price volatility while limiting the firm natural gas customers’ exposure to adverse changes in the market price of natural gas. The hedge program requires that DPL hedge, on a non-discretionary basis, an amount equal to 50% of estimated purchase requirements for each month, including estimated monthly purchases for storage injections. The 50% hedge monthly target is achieved by hedging 1/12th of the 50% target each month beginning 12-months prior to the month in which the physical gas is to be purchased. Currently, DPL uses only exchange traded futures for its gas hedging program, which are considered derivatives, however, it retains the capability to employ other physical and financial hedges if needed. DPL has not elected hedge accounting for these derivative financial instruments. Because of the DPSC-approved fuel adjustment clause for DPL's derivatives, the change in fair value of the derivatives each period, in addition to all premiums paid and other transaction costs incurred as part of the gas hedging program, are fully recoverable and are recorded by DPL as regulatory assets or liabilities. DPL’s physical gas purchases are currently all daily, monthly or intra-month transactions. From time to time, DPL will enter into seasonal purchase or sale arrangements, however, there are none currently in the portfolio. Certain of DPL's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

ACE has contracts to procure BGS electric supply that are executed through a competitive procurement process approved by the NJBPU. The BGS rates charged recover ACE's wholesale power supply costs. ACE does not make any profit or incur any loss on the supply component of the BGS it supplies to customers. ACE’s commodity price risk related to electric supply procurement is limited. ACE locks in fixed prices for all of its BGS requirements through full requirements contracts. Certain of ACE’s full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other ACE full requirements contracts are not derivatives.

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. Proprietary trading activities are subject to limits established by Exelon’s RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the 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 revenue from energy marketing activities. 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. For the three months ended March 31, 2019 and 2018 Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses) which are also included in the "Net fair value changes related to derivatives" in the

Consolidated Statements of Cash Flows. The Utility Registrants do not execute derivatives for proprietary trading purposes.

	Three Months Ended March 31,	
	2019	2018
Income Statement Location	Gain (Loss)	
Operating revenues	$ 2	$ 2

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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 $1,419 million and $1,420 million at March 31, 2019 and December 31, 2018, respectively, for Exelon and $619 million and $620 million at March 31, 2019 and December 31, 2018, 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 $209 million and $268 million at March 31, 2019 and December 31, 2018, respectively.

The mark-to-market derivative assets and liabilities as of March 31, 2019 and December 31, 2018 and the mark-to-market gains and losses for the three months ended March 31, 2019 and 2018 were not material for Exelon and Generation.

Credit Risk, Collateral and Contingent-Related Features (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. 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.

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The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of March 31, 2019. 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. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of $36 million, $31 million, $27 million, $37 million, $5 million and $4 million as of March 31, 2019, respectively.

Rating as of March 31, 2019	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	$ 819	$ 11	$ 808	1	$ 135
Non-investment grade	86	39	47		
No external ratings					
Internally rated — investment grade	162	—	162		
Internally rated — non-investment grade	87	7	80		
Total	$ 1,154	$ 57	$ 1,097	1	$ 135

Net Credit Exposure by Type of Counterparty	As of March 31, 2019
Financial institutions	$ 13
Investor-owned utilities, marketers, power producers	762
Energy cooperatives and municipalities	287
Other	35
Total	$ 1,097

(a) As of March 31, 2019, credit collateral held from counterparties where Generation had credit exposure included $37 million of cash and $19 million of letters of credit. The credit collateral does not include non-liquid collateral.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on daily, updated forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price on a given day, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of March 31, 2019, ComEd's net credit exposure to suppliers was $2 million.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 4 — Regulatory Matters of the Exelon 2018 Form 10-K for additional information.

PECO's unsecured credit used by the suppliers represents PECO's net credit exposure. As of March 31, 2019, PECO had no material net credit exposure to its electric suppliers.

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. As of March 31, 2019, PECO had no material credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE’s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 4 — Regulatory Matters of the Exelon 2018 Form 10-K for additional information.

BGE’s full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier’s performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. As of March 31, 2019, BGE's net credit exposure to suppliers was immaterial.

BGE’s regulated gas business is exposed to market-price risk. At March 31, 2019, BGE's credit exposure related to off-system sales, which is mitigated by parental guarantees, letters of credit or right to offset clauses within other contracts with those third-party suppliers, was immaterial.

Pepco’s, DPL's and ACE's power procurement contracts provide suppliers with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier’s lowest credit rating from the major credit rating agencies and the supplier’s tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier’s unsecured credit limit. The unsecured credit used by the suppliers represents Pepco’s, DPL's and ACE's net credit exposure. As of March 31, 2019, Pepco’s, DPL's and ACE's net credit exposures to suppliers were immaterial.

Pepco is permitted to recover its costs of procuring energy through the MDPSC-approved and DCPSC-approved procurement tariffs. DPL is permitted to recover its costs of procuring energy through the MDPSC-approved and DPSC-approved procurement tariffs. ACE is permitted to recover its costs of procuring energy through the NJBPU-approved procurement tariffs. Pepco’s, DPL's and ACE's counterparty credit risks are mitigated by their ability to recover realized energy costs through customer rates. See Note 2 — Regulatory Matters of the Exelon 2018 Form 10-K for additional information.

DPL’s natural gas procurement plan is reviewed and approved annually on a prospective basis by the DPSC. DPL’s counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the GCR, which allows DPL to adjust rates annually to reflect realized natural gas prices. To the extent that the fair value of the transactions in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. Exchange-traded contracts are required to be fully collateralized without regard to the credit rating of the holder. As of March 31, 2019, DPL's credit exposure under its natural gas supply and asset management agreements with investment grade suppliers was immaterial.

Collateral (All Registrants)

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.

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The aggregate fair value of all derivative instruments with credit-risk related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

Credit-Risk Related Contingent Features	March 31, 2019	December 31, 2018
Gross fair value of derivative contracts containing this feature[(a)]	$ (1,667)	$ (1,723)
Offsetting fair value of in-the-money contracts under master netting arrangements[(b)]	1,177	1,105
Net fair value of derivative contracts containing this feature[(c)]	$ (490)	$ (618)

(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.

Generation had cash collateral posted of $542 million and letters of credit posted of $289 million and cash collateral held of $56 million and letters of credit held of $26 million as of March 31, 2019 for external counterparties with derivative positions. Generation had cash collateral posted of $418 million and letters of credit posted of $367 million and cash collateral held of $47 million and letters of credit held of $44 million at December 31, 2018 for external counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e., to BB+ by S&P or Ba1 by Moody’s), Generation would have been required to post additional collateral of $1.9 billion and $2.1 billion as of March 31, 2019 and December 31, 2018, respectively. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Exelon's interest rate swaps contain provisions that, in the event of a merger, if Exelon’s debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of March 31, 2019, Exelon's swaps were in a liability position that is not material.

See Note 24 — Segment Information of the Exelon 2018 Form 10-K for additional information regarding the letters of credit supporting the cash collateral.

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. Under the terms of ComEd’s standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of March 31, 2019, ComEd held $11 million in collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's REC and ZEC contracts, collateral postings are required to cover a percentage of the REC and ZEC contract value. As of March 31, 2019, ComEd held $31 million in collateral from suppliers for REC and ZEC contract obligations. Under the terms of ComEd’s long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and

energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of March 31, 2019, ComEd held $19 million in collateral from suppliers for the long-term renewable energy contracts. If ComEd lost its investment grade credit rating as of March 31, 2019, it would have been required to post approximately $8 million of collateral to its counterparties. See Note 4 — Regulatory Matters of the Exelon 2018 Form 10-K for additional information.
PECO’s natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO’s credit rating

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from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of March 31, 2019, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of March 31, 2019, PECO could have been required to post $34 million of collateral to its counterparties.

PECO’s supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

BGE’s natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE’s credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of March 31, 2019, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of March 31, 2019, BGE could have been required to post $46 million of collateral to its counterparties.

DPL's natural gas procurement contracts contain provisions that could require DPL to post collateral. To the extent that the fair value of the natural gas derivative transaction in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. The DPL obligations are standalone, without the guaranty of PHI. If DPL lost its investment grade credit rating as of March 31, 2019, DPL could have been required to post an additional amount of $14 million of collateral to its counterparties.

BGE's, Pepco's, DPL's and ACE's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE, Pepco, DPL or ACE to post collateral.

11. Debt and Credit Agreements (All Registrants)

Short-Term Borrowings

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

Commercial Paper

The following table reflects the Registrants' commercial paper programs as of March 31, 2019 and December 31, 2018. Generation and PECO had no commercial paper borrowings as of both March 31, 2019 and December 31, 2018.

Commercial Paper Issuer	Outstanding Commercial Paper at March 31, 2019	December 31, 2018	Average Interest Rate on Commercial Paper Borrowings as of March 31, 2019	December 31, 2018
Exelon	$ 629	$ 89	2.63 %	2.15 %
ComEd	322	—	2.64 %	2.14 %
BGE	106	35	2.59 %	2.18 %
PHI	201	54	2.62 %	2.15 %
PEPCO	105	40	2.62 %	2.24 %
DPL	5	—	2.61 %	2.07 %
ACE	91	14	2.62 %	2.21 %

See Note 13— Debt and Credit Agreements of the Exelon 2018 Form 10-K for additional information on the Registrants’ credit facilities.

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Short-Term Loan Agreements

On March 23, 2017, Exelon Corporate entered into a term loan agreement for $500 million, which was renewed on March 22, 2018 with an expiration of March 21, 2019. The loan agreement was renewed on March 20, 2019 and will expire on March 19, 2020. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.95% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's Consolidated Balance Sheet within Short-Term borrowings.

Credit Agreements

On February 21, 2019, Generation entered into a credit agreement establishing a $100 million bilateral credit facility. The facility will mature in March 2021. This facility will solely be used by Generation to issue letters of credit.

Long-Term Debt

Issuance of Long-Term Debt

During the three months ended March 31, 2019, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Energy Efficiency Project Financing	3.95 %	August 31, 2020	$ 2	Funding to install energy conservation measures for the Fort Meade project.
ComEd	First Mortgage Bonds, Series 126	4.00 %	March 1, 2049	$ 400	Repay a portion of ComEd’s outstanding commercial paper obligations and fund other general corporate purposes.

Debt Covenants

As of March 31, 2019, the Registrants are in compliance with debt covenants, except for Antelope Valley's nonrecourse debt event of default as discussed below.

Nonrecourse Debt

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

Antelope Valley Solar Ranch One. In December 2011, the DOE Loan Programs Office issued a guarantee for up to $646 million for a nonrecourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project became fully operational in 2014. The loan will mature on January 5, 2037. As of March 31, 2019, $502 million was outstanding. 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 Pacific Gas and Electric Company (PG&E) through a PPA. On January 29, 2019, PG&E filed for protection under Chapter 11 of the U.S. Bankruptcy Code, which created an event of default for Antelope Valley’s nonrecourse debt that provides the lender with a right to accelerate amounts outstanding under the loan such that they would become immediately due and payable. As a result of the ongoing event of default and the absence of a waiver from the lender foregoing their acceleration rights, the debt was reclassified as current in Exelon’s and Generation’s Consolidated Balance Sheets as of March 31, 2019. Further, distributions from Antelope Valley to EGR IV are currently suspended.

ExGen Renewables IV. In November 2017, EGR IV, an indirect subsidiary of Exelon and Generation, entered into an $850 million nonrecourse senior secured term loan credit facility agreement. Generation’s interests in EGRP, Antelope Valley, SolGen, and Albany Green Energy were all contributed to and are pledged as collateral for this financing. The loan is scheduled to mature on November 28, 2024. As of March 31, 2019, $834 million was outstanding.

Although Antelope Valley’s debt is in default, it is nonrecourse to EGR IV. However, if in the future Antelope Valley were to file for bankruptcy protection as a result of events culminating from PG&E’s bankruptcy proceedings this

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would represent an event of default for EGR IV's debt that would provide the lender with an opportunity to accelerate EGR IV's debt.

See Note 13— Debt and Credit Agreements of the Exelon 2018 Form 10-K for additional information on nonrecourse debt.

12. Income Taxes (All Registrants)

Rate Reconciliation

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

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

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	Three Months Ended March 31, 2018								
	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	4.1	2.4	8.2	(3.9)	6.3	4.6	1.7	6.3	6.6
Qualified NDT fund income	(0.4)	(1.3)	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.3)	(4.3)	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.2)	(0.3)
Plant basis differences	(2.7)	—	0.1	(14.2)	(0.7)	(2.6)	(3.4)	(1.3)	(2.6)
Production tax credits and other credits	(2.8)	(9.5)	(0.1)	—	—	—	—	—	—
Noncontrolling interests	(0.7)	(2.5)	—	—	—	—	—	—	—
Excess deferred tax amortization	(6.0)	—	(7.5)	(4.8)	(8.6)	(10.6)	(12.8)	(7.9)	(8.7)
Other	(2.8)	(1.3)	0.3	0.2	—	—	(0.3)	0.5	(3.5)
Effective income tax rate	8.4%	4.5%	21.8%	(1.8)%	17.9%	12.2%	6.1%	18.4%	12.5%

Accounting for Uncertainty in Income Taxes

The Registrants have the following unrecognized tax benefits as of March 31, 2019 and December 31, 2018:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
March 31, 2019	$ 448	$ 411	$ —	$ —	$ —	$45	$ —	$ —	$ 14

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2018	$ 477	$ 408	$ 2	$ —	$ —	$45	$ —	$ —	$ 14

In 2016, the Tax Court held that Exelon was not entitled to defer a gain on its 1999 like-kind exchange transaction. In addition to the tax and interest related to the gain deferral, the Tax Court also ruled that Exelon was liable for penalties and interest on the penalties. Exelon had fully paid the amounts assessed resulting from the Tax Court decision in 2017. In September 2017, Exelon appealed the Tax Court decision to the U.S. Court of Appeals for the Seventh Circuit. In October 2018, the U.S. Court of Appeals for the Seventh Circuit affirmed the Tax Court’s decision. Exelon filed a petition seeking rehearing of the Seventh Circuit’s decision, but the Seventh Circuit denied that petition in December 2018.

In the first quarter of 2019, Exelon elected not to seek a further review by the U.S. Supreme Court. As a result, Exelon's and ComEd's unrecognized tax benefits decreased by approximately $33 million and $2 million, respectively, in the first quarter of 2019.

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

Settlement of Income Tax Audits, Refund Claims, and Litigation

As of March 31, 2019, Exelon, Generation, PHI and ACE have approximately $425 million, $411 million, $14 million and $14 million of 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, and the outcomes of pending court cases. Of the above unrecognized tax benefits, Exelon and Generation have $411 million that, if recognized, would

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decrease the effective tax rate. The unrecognized tax benefits related to PHI and ACE, if recognized, may be included in future regulated base rates and that portion would have no impact to the effective tax rate.

13. Nuclear Decommissioning (Exelon and Generation)

Nuclear Decommissioning Asset Retirement Obligations (Exelon and Generation)

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

The following table provides a rollforward of the nuclear decommissioning ARO reflected in Exelon's and Generation's Consolidated Balance Sheets from December 31, 2018 to March 31, 2019:

Nuclear decommissioning ARO at December 31, 2018 [a][b]	$10,005
Net increase due to changes in, and timing of, estimated future cash flows	223
Accretion expense	120
Costs incurred related to decommissioning plants	(19)
Nuclear decommissioning ARO at March 31, 2019 [a][b]	$10,329

(a) Includes $41 million and $22 million as the current portion of the ARO at March 31, 2019 and December 31, 2018, respectively, which is included in Other current liabilities in Exelon's and Generation's Consolidated Balance Sheets.

(b) Includes $760 million and $772 million of ARO related to Oyster Creek which is classified as Liabilities held for sale in Exelon's and Generation's Consolidated Balance Sheets at March 31, 2019 and December 31, 2018, respectively. See Note 3 — Mergers, Acquisitions and Dispositions for additional information.

During the three months ended March 31, 2019, Exelon's and Generation's total nuclear ARO increased by approximately $324 million, primarily reflecting the impacts of ARO updates completed during first quarter 2019 and the accretion of the ARO liability due to the passage of time. The first quarter 2019 ARO update includes an increase of approximately $330 million for a change in the assumed retirement timing probabilities for certain economically challenged nuclear plants and a $110 million decrease for the impacts of revised decommissioning cost estimates for TMI which incorporate site specific decommissioning planning activities in anticipation of its September 2019 shutdown date. Approximately $85 million of the TMI ARO adjustment resulted in a decrease in Operating and maintenance expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. See Note 8 — Early Plant Retirements for additional information.

NDT Funds (Exelon and Generation)

Exelon and Generation had NDT funds totaling $13,345 million and $12,695 million at March 31, 2019 and December 31, 2018, respectively. The NDT funds include $881 million and $890 million at March 31, 2019 and December 31, 2018, respectively, related to Oyster Creek NDT funds which are classified as Assets held for sale in Exelon's and Generation's Consolidated Balance Sheets. See Note 3 — Mergers, Acquisitions and Dispositions for additional information regarding the announced pending sale of Oyster Creek. The NDT funds also include $163 million and $144 million for the current portion of the NDT funds at March 31, 2019 and December 31, 2018, 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 (Exelon and Generation)

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.

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Generation filed its biennial decommissioning funding status report with the NRC on April 1, 2019 for all 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. 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 15 — Asset Retirement Obligations of the Exelon 2018 Form 10-K for information regarding the amount collected from PECO ratepayers for decommissioning cost.

14. Retirement Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all current employees. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Effective February 1, 2018, most newly-hired Generation and BSC non-represented employees are not eligible for pension benefits and will instead be eligible to receive an enhanced non-discretionary employer contribution in an Exelon defined contribution savings plan. Effective January 1, 2018, most newly-hired non-represented employees are not eligible for OPEB benefits and employees represented by Local 614 are not eligible for retiree health care benefits.

Effective January 1, 2019, Exelon merged the Exelon Corporation Cash Balance Pension Plan (CBPP) into the Exelon Corporation Retirement Program (ECRP). The merging of the plans is not changing the benefits offered to the plan participants and, thus, has no impact on Exelon's pension obligation. However, beginning in 2019, actuarial losses and gains related to the CBPP and ECRP are being amortized over participants' average remaining service period of the merged ECRP rather than each individual plan.

Defined Benefit Pension and Other Postretirement Benefits

During the first quarter of 2019, Exelon received an updated valuation of its pension and OPEB to reflect actual census data as of January 1, 2019. This valuation resulted in an increase to the pension and OPEB obligations of $75 million and $36 million, respectively. Additionally, accumulated other comprehensive loss increased by $39 million (after-tax) and regulatory assets and liabilities increased by $53 million and decreased by $5 million, respectively.

The majority of the 2019 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 4.31%. The majority of the 2019 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.67% for funded plans and a discount rate of 4.30%.

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A portion of the net periodic benefit cost for all plans is capitalized within the Consolidated Balance Sheets. The following table presents the components of Exelon's net periodic benefit costs, prior to capitalization, for the three months ended March 31, 2019 and 2018.

	Pension Benefits Three Months Ended March 31,		Other Postretirement Benefits Three Months Ended March 31,	
	2019	2018	2019	2018
Components of net periodic benefit cost:				
Service cost	$89	$101	$ 24	$ 28
Interest cost	221	201	47	43
Expected return on assets	(307)	(312)	(38)	(43)
Amortization of:				
Prior service cost (benefit)	—	—	(45)	(46)
Actuarial loss	104	157	11	16
Net periodic benefit cost	$107	$147	$ (1)	$ (2)

The amounts below represent Exelon's, Generation's, ComEd's, PECO's, BGE's, PHI's, Pepco's, DPL's, and ACE's pension and postretirement benefit plan costs. For Exelon, the service cost component is included in Operating and maintenance expense and Property, plant and equipment, net, for the three months ended March 31, 2019 and 2018, while the non-service cost components are included in Other, net and Regulatory assets for the three months ended March 31, 2019 and 2018. For the Registrants other than Exelon, the service cost and non-service cost components are included in Operating and maintenance expense and Property, plant and equipment, net in their consolidated financial statements for the three months ended March 31, 2019 and 2018.

	Three Months Ended March 31,	
Pension and Other Postretirement Benefit Costs	2019	2018
Exelon	$106	$145
Generation	31	51
ComEd	24	45
PECO	2	5
BGE	16	15
PHI	23	15
Pepco	6	4
DPL	4	—
ACE	4	3

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Defined Contribution Savings Plans

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the three months ended March 31, 2019 and 2018, respectively.

	Three Months Ended March 31,	
Savings Plan Matching Contributions	2019	2018
Exelon	$31	$ 32
Generation	13	15
ComEd	7	7
PECO	2	2
BGE	2	2
PHI	4	3
Pepco	1	1
DPL	1	1
ACE	1	—

15. Changes in Accumulated Other Comprehensive Income (Exelon and Generation)

The following tables present changes in accumulated other comprehensive income (loss) (AOCI) by component for the three months ended March 31, 2019 and 2018:

Three Months Ended March 31, 2019	Gains (Losses) on Cash Flow Hedges	Unrealized Gains (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Investments in Unconsolidated Affiliates	Total
Exelon[(a)]						
Beginning balance	$ (2)	$ —	$ (2,960)	$ (33)	$ —	$(2,995)
OCI before reclassifications	—	—	(38)	2	(1)	(37)
Amounts reclassified from AOCI[(b)]	—	—	20	—	—	20
Net current-period OCI	—	—	(18)	2	(1)	(17)
Ending balance	$ (2)	$ —	$ (2,978)	$ (31)	$ (1)	$(3,012)
Generation[(a)]						
Beginning balance	$ (4)	$ —	$ —	$ (33)	$ (1)	$(38)
OCI before reclassifications	—	—	—	2	(1)	1
Amounts reclassified from AOCI	1	—	—	—	—	1
Net current-period OCI	1	—	—	2	(1)	2
Ending balance	$ (3)	$ —	$ —	$ (31)	$ (2)	$(36)

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Three Months Ended March 31, 2018	Gains (Losses) on Cash Flow Hedges	Unrealized gains (losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Investments in Unconsolidated Affiliates	Total
Exelon[(a)]						
Beginning balance	$ (14)	$ 10	$ (2,998) [(d)]	$ (23)	$ (1)	$ (3,026)
OCI before reclassifications	8	—	18	1	—	27
Amounts reclassified from AOCI[(b)]	—	—	44	—	—	44
Net current-period OCI	8	—	62	1	—	71
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard[(c)]	—	(10)	—	—	—	(10)
Ending balance	$ (6)	$ —	$ (2,936)	$ (22)	$ (1)	$ (2,965)
Generation[(a)]						
Beginning balance	$ (16)	$ 3	$ —	$ (23)	$ (1)	$ (37)
OCI before reclassifications	7	—	—	(1)	—	6
Amounts reclassified from AOCI	—	—	—	—	—	—
Net current-period OCI	7	—	—	(1)	—	6
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard[(c)]	—	(3)	—	—	—	(3)
Ending balance	$ (9)	$ —	$ —	$ (24)	$ (1)	$ (34)

(a) All amounts are net of tax and noncontrolling interests. Amounts in parenthesis represent a decrease in AOCI.
(b) See next tables for details about these reclassifications.
(c) Exelon prospectively adopted the new standard Recognition and Measurement of Financial Assets and Liabilities. The standard was adopted as of January 1, 2018, which resulted in an increase to Retained earnings and Accumulated other comprehensive loss of $10 million and $3 million for Exelon and Generation, respectively. The amounts reclassified related to Rabbi Trusts. See Note 1 — Significant Accounting Policies of the Exelon 2018 Form 10-K for additional information.
(d) Exelon early adopted the new standard Reclassification of Certain Tax Effects from AOCI. The standard was adopted retrospectively as of December 31, 2017, which resulted in an increase to Exelon's Retained earnings and Accumulated other comprehensive loss of $539 million, primarily related to deferred income taxes associated with Exelon's pension and OPEB obligations. See Note 1 — Significant Accounting Policies of the Exelon 2018 Form 10-K for additional information.

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Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE did not have any reclassifications out of AOCI to Net income during the three months ended March 31, 2019 and 2018. The following tables present amounts reclassified out of AOCI to Net income for Exelon during the three months ended March 31, 2019 and 2018.

Three Months Ended March 31, 2019

Details about AOCI components	Items reclassified out of AOCI[a]	Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	
Amortization of pension and other postretirement benefit plan items		
Prior service costs[b]	$ 22	
Actuarial losses[b]	(49)	
	(27)	Total before tax
	7	Tax benefit
	$ (20)	Net of tax
Total Reclassifications	$ (20)	Net of tax

Three Months Ended March 31, 2018

Details about AOCI components	Items reclassified out of AOCI[a]	Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	
Amortization of pension and other postretirement benefit plan items		
Prior service costs[b]	$ 23	
Actuarial losses[b]	(83)	
	(60)	Total before tax
	16	Tax benefit
	$ (44)	Net of tax
Total Reclassifications	$ (44)	Net of tax

(a) Amounts in parenthesis represent a decrease in net income.
(b) This AOCI component is included in the computation of net periodic pension and OPEB cost. See Note 14 — Retirement Benefits for additional information.

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The following table presents income tax benefit (expense) allocated to each component of other comprehensive income (loss) during the three months ended March 31, 2019 and 2018:

	Three Months Ended March 31, 2019	2018
Exelon		
Pension and non-pension postretirement benefit plans:		
Prior service benefit reclassified to periodic benefit cost	$6	$6
Actuarial loss reclassified to periodic benefit cost	(13)	(22)
Pension and non-pension postretirement benefit plans valuation adjustment	14	(7)
Change in unrealized loss on cash flow hedges	—	(3)
Change in unrealized loss on investments in unconsolidated affiliates	—	(1)
Total	$7	$(27)
Generation		
Change in unrealized gain (loss) on cash flow hedges	$1	$(3)
Change in unrealized loss on investments in unconsolidated affiliates	—	(1)
Total	$1	$(4)

16. Commitments and Contingencies (All Registrants)

The following is an update to the current status of commitments and contingencies set forth in Note 22 of the Exelon 2018 Form 10-K. See Note 5 — Mergers, Acquisitions and Dispositions of the Exelon 2018 Form 10-K for additional information on the PHI Merger commitments.

Commitments

PHI Merger Commitments (Exelon, PHI, Pepco, DPL and ACE). The merger of Exelon and PHI was approved in Delaware, New Jersey, Maryland and the District of Columbia. Exelon and PHI agreed to certain commitments including where applicable: customer rate credits, funding for energy efficiency and delivery system modernization programs, a green sustainability fund, workforce development initiatives, charitable contributions, renewable generation and other required commitments. In addition, the orders approving the merger in Delaware, New Jersey, and Maryland include a “most favored nation” provision which, generally, requires allocation of merger benefits proportionally across all the jurisdictions.

The following amounts represent total commitment costs for Exelon, PHI, Pepco, DPL and ACE that have been recorded since the acquisition date and the remaining obligations as of March 31, 2019:

Description	Expected Payment Period	Exelon	PHI	Pepco	DPL	ACE
Rate credits	2016 - 2021	$ 264	$264	$ 91	$ 72	$101
Energy efficiency	2016 - 2021	117	—	—	—	—
Charitable contributions	2016 - 2026	50	50	28	12	10
Delivery system modernization	Q2 2017	22	—	—	—	—
Green sustainability fund	Q2 2017	14	—	—	—	—
Workforce development	2016 - 2020	17	—	—	—	—
Other		29	6	1	5	—
Total commitments		$ 513	$320	$ 120	$ 89	$111
Remaining commitments		$ 123	$90	$ 71	$ 12	$7

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In addition, Exelon is committed to develop or to assist in the commercial development of approximately 37 MWs of new solar generation in Maryland, District of Columbia, and Delaware at an estimated cost of approximately $127 million, which will generate future earnings at Exelon and Generation. Investment costs, which are expected to be primarily capital in nature, will be recognized as incurred and recorded in Exelon's and Generation's financial statements. As of March 31, 2019, 27 MWs of new generation were developed and Exelon and Generation have incurred costs of $97 million. Exelon has also committed to purchase 100 MWs of wind energy in PJM. DPL has committed to conducting three RFPs to procure up to a total of 120 MWs of wind RECs for the purpose of meeting Delaware's renewable portfolio standards. DPL has conducted two of the three wind REC RFPs. The first 40 MW wind REC tranche was conducted in 2017 and did not result in a purchase agreement. The second 40 MW wind REC tranche was conducted in 2018 and resulted in a proposed REC purchase agreement that was approved by the DPSC in March 2019. The third and final 40 MW wind REC tranche will be conducted in 2022.

Pursuant to the various jurisdictions' merger approval conditions, over specified periods Pepco, DPL and ACE are not permitted to reduce employment levels due to involuntary attrition associated with the merger integration process and have made other commitments regarding hiring and relocation of positions.

Commercial Commitments (All Registrants). The Registrants’ commercial commitments as of March 31, 2019, representing commitments potentially triggered by future events were as follows:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Letters of credit	$1,480	$ 1,455	$ 6	$ —	$ 2	$8	$ 8	$ —	$ —
Surety bonds[(a)]	1,597	1,376	51	9	17	40	32	5	3
Financing trust guarantees	378	—	200	178	—	—	—	—	—
Guaranteed lease residual values[(b)]	26	—	—	—	—	26	8	11	7
Total commercial commitments	$3,481	$ 2,831	$ 257	$ 187	$ 19	$74	$ 48	$ 16	$ 10

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

(b) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $68 million, $22 million of which is a guarantee by Pepco, $28 million by DPL and $17 million by ACE. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

Nuclear Insurance (Exelon and Generation). Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations. Generation has mitigated its financial exposure to these risks through insurance and other industry risk-sharing provisions.

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and also to limit the liability of nuclear reactor owners for such claims from any single incident. As of March 31, 2019, the current liability limit per incident is $14.1 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. Changes to account for the effects of inflation occur at least once every five years with the last adjustment effective November 1, 2018. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. Effective January 1, 2017, the required amount of nuclear energy liability insurance purchased is $450 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool, as required by the Price Anderson-Act, which provides the additional $13.6 billion per incident in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Exelon's share of this secondary layer would be approximately $3.1 billion, however any amounts payable under this secondary layer would be capped at $454 million per year.

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In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $14.1 billion limit for a single incident.

As part of the execution of the NOSA on April 1, 2014, Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this indemnity. See Note 2 — Variable Interest Entities of the Exelon 2018 Form 10-K for additional information on Generation's operations relating to CENG.

Generation is required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years NEIL has made distributions to its members, but Generation cannot predict the level of future distributions or if they will continue at all.

Premiums paid to NEIL by its members are also subject to a potential assessment for adverse loss experience in the form of a retrospective premium obligation. NEIL has never assessed this retrospective premium since its formation in 1973, and Generation cannot predict the level of future assessments if any. The current maximum aggregate annual retrospective premium obligation for Generation is approximately $335 million. NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

NEIL provides "all risk" property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, Generation is unable to predict the timing of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery by Exelon will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses.

For its insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by Generation. Any such losses could have a material adverse effect on Exelon's and Generation's financial condition, results of operations and cash flows.

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 in the Registrants' financial statements.

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

MGP Sites (Exelon, ComEd, PECO, BGE, PHI and DPL). 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 identified 42 sites, 21 of which have been remediated and approved by the Illinois EPA or the U.S. EPA and 21 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 2023.
- PECO has identified 26 sites, 17 of which have been remediated in accordance with applicable PA DEP regulatory requirements and 9 that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2022.
- BGE has identified 13 sites, 9 of which have been remediated and approved by the MDE and 4 that require some level of remediation and/or ongoing activity. BGE expects the majority of the remediation at these sites to continue through at least 2019.
- DPL has identified 3 sites, for 2 of which remediation has been completed and approved by the MDE or the Delaware Department of Natural Resources and Environmental Control. The remaining site is 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. See Note 6 — Regulatory Matters for additional information regarding the associated regulatory assets. While BGE and DPL do not have riders for MGP clean-up costs, they have historically received recovery of actual clean-up costs in distribution rates.

As of March 31, 2019 and December 31, 2018, the Registrants had accrued the following undiscounted amounts for environmental liabilities in Other current liabilities and Other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

March 31, 2019	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 486	$ 347
Generation	108	—
ComEd	320	318
PECO	27	25
BGE	5	4
PHI	26	—
Pepco	24	—
DPL	1	—
ACE	1	—

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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December 31, 2018	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 496	$ 356
Generation	108	—
ComEd	329	327
PECO	27	25
BGE	5	4
PHI	27	—
Pepco	25	—
DPL	1	—
ACE	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 the final remedy. The ROD modified the EPA’s previously proposed plan for partial excavation of the radiological materials by reducing the depths of the excavation. The ROD also allows for variation in depths of excavation depending on radiological concentrations. The EPA and the PRPs are negotiating Consent Agreements to design and implement the ROD remedy, and negotiations are expected to be completed in the first quarter of 2020. The estimated cost of the remedy, taking into account the current EPA technical requirements and the total costs expected to be incurred 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 remediation 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 Generation’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 RI/FS. The purpose of this RI/FS is to define the nature and extent of any groundwater contamination from the West Lake Landfill site and evaluate remedial alternatives. Generation estimates the undiscounted cost for the groundwater RI/FS to be approximately $20 million. Generation determined a loss associated with the RI/FS is probable and has recorded a liability included in the table above that reflects management’s best estimate of Cotter’s allocable share of the cost among the PRPs. At this time Generation cannot predict the likelihood or the extent to which, if any, remediation activities may be required and therefore cannot estimate a reasonably possible range of loss for response costs beyond those associated with the RI/FS component. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Exelon’s and Generation’s future financial statements.

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

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 indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. Government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under FUSRAP. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million from all PRPs. Pursuant to a series of annual agreements since 2011, the DOJ and the PRPs have tolled the statute of limitations until August 2019 so that settlement discussions could proceed. Generation has determined that a loss associated with this matter is probable under its indemnification agreement with Cotter and has recorded an estimated liability, which is included in the table above.
Commencing in February 2012, a number of lawsuits have been filed in the U.S. District Court for the Eastern District of Missouri. Among the defendants were Exelon, Generation and ComEd, all of which were subsequently dismissed from the case, as well as Cotter, which remains a defendant. The suits allege that individuals living in the North St. Louis area developed some form of cancer or other serious illness due to Cotter's negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs are asserting public liability claims under the Price-Anderson Act. Their state law claims for negligence, strict liability, emotional distress, and medical monitoring have been dismissed. In the event of a finding of liability against Cotter, it is probable that Generation would be financially responsible due to its indemnification responsibilities of Cotter described above. The court has dismissed a number of the lawsuits as untimely, which has been upheld on appeal. Cotter and the remaining plaintiffs have engaged in settlement discussions pursuant to court-ordered mediation. During the second quarter of 2018, Generation determined a loss was probable based on the advancement of settlement proceedings and recorded an immaterial liability.
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. That generating facility was deactivated in June 2012 and plant structure demolition was completed in July 2015. 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 Remediation Investigation (RI)/ Feasibility Study (FS) for the Benning Road site and an approximately 10 to 15-acre portion of the adjacent Anacostia River. The RI/FS will form the basis for the remedial actions for the Benning Road site and for the Anacostia River sediment associated with the site. The Consent Decree does not obligate Pepco or Pepco Energy Services to pay for or perform any remediation work, but it is anticipated that DOEE will look to Pepco and Pepco Energy Services to assume responsibility for cleanup of any conditions in the river that are determined to be attributable to past activities at the Benning Road site. Pursuant to Exelon's March 23, 2016 acquisition of PHI, Pepco Energy Services was transferred to Generation.
Since 2013, Pepco and Pepco Energy Services (now Generation) have been performing RI work and have submitted multiple draft RI reports to the DOEE. Once the RI work is completed, Pepco and Generation will issue a draft "final" RI report for review and comment by DOEE and the public. Pepco and Generation will then proceed to develop an FS to evaluate possible remedial alternatives for submission to DOEE. The Court has established a schedule for completion of the RI and FS, and approval by the DOEE, by September 16, 2021.
Upon DOEE's approval of the final RI and FS Reports, Pepco and Generation will have satisfied their obligations under the Consent Decree. At that point, DOEE will prepare a Proposed Plan regarding further response actions. After

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

Anacostia River Tidal Reach (Exelon, PHI and Pepco). Contemporaneous with the Benning RI/FS being performed by Pepco and Generation, DOEE and certain federal agencies have been conducting a separate RI/FS focused on the entire tidal reach of the Anacostia River extending from just north of the Maryland-D.C. boundary line to the confluence of the Anacostia and Potomac Rivers. In March 2016, DOEE released a draft of the river-

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wide RI Report for public review and comment. 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 addressing the entire tidal reach of the river 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 RI/FS. Pepco responded that it will participate in the Consultative Working Group, but its participation is not an acceptance of any financial responsibility beyond the work that will be performed at the Benning Road site described above. In April 2018, DOEE released a draft remedial investigation report for public review and comment. Pepco submitted written comments to the draft RI and participated in a public hearing. Pepco continues outreach efforts as appropriate to the agencies, governmental officials, community organizations and other key stakeholders. In May 2018 the District of Columbia Council extended the deadline for completion of the Record of Decision from June 30, 2018 until December 31, 2019. An appropriate liability for Pepco's share of investigation costs has been accrued and is included in the table above. Although Pepco has determined that it is probable that costs for remediation will be incurred, Pepco cannot estimate the reasonably possible range of loss at this time and no liability has been accrued for those future costs. A draft Feasibility Study of potential remedies and their estimated costs is being prepared by the agencies and is expected later in 2019, at which time Pepco will likely be in a better position to estimate the range of loss.

In addition to the activities associated with the remedial process outlined above, there is a complementary statutory program that requires an assessment to determine if any natural resources have been damaged as a result of the contamination that is being remediated, and, if so, that a plan be developed by the federal, state and local Trustees responsible for those resources to restore them to their condition before injury from the environmental contaminants. If natural resources are not restored, then compensation for the injury can be sought from the party responsible for the release of the contaminants. The assessment of Natural Resource Damages (NRD) typically takes place following cleanup because cleanups sometimes also effectively restore habitat. 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 it cannot reasonably estimate the range of loss.

Litigation and Regulatory Matters

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

At March 31, 2019 and December 31, 2018, Generation had recorded estimated liabilities of approximately $77 million and $79 million, respectively, in total for asbestos-related bodily injury claims. As of March 31, 2019, approximately $25 million of this amount related to 239 open claims presented to Generation, while the remaining $52 million is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, 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.

There is a reasonable possibility that Exelon may have additional exposure to estimated future asbestos-related bodily injury claims in excess of the amount accrued and the increases could have a material unfavorable impact on Exelon's and Generation's financial statements.

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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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. Generation vigorously contested the City's claims before the EACC and will continue to do so in the Massachusetts Superior Court proceeding. Generation continues to believe that the City's claim lacks merit. Accordingly, Generation has not recorded a liability for payment resulting from such a revocation, nor can Generation estimate a reasonably possible range of loss, if any, associated with any such revocation. Further, it is reasonably possible that property taxes assessed in future periods, including those following the expiration of the current TIF Agreement in 2019, could be material to Generation's results of operations and cash flows.

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.

17. Supplemental Financial Information (All Registrants)

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants' Consolidated Statements of Operations and Comprehensive Income for the three months ended March 31, 2019 and 2018.

	Three Months Ended March 31, 2019								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on NDT funds[a]									
Regulatory agreement units[b]	$54	$ 54	$ —	$ —	$ —	$—	$ —	$ —	$ —
Non-regulatory agreement units	54	54	—	—	—	—	—	—	—
Net unrealized gains on NDT funds									
Regulatory agreement units[b]	379	379	—	—	—	—	—	—	—
Non-regulatory agreement units	280	280	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities[c]	(348)	(348)	—	—	—	—	—	—	—
Total decommissioning-related activities	419	419	—	—	—	—	—	—	—
Investment income	12	7	—	1	—	—	—	—	—
Interest income related to uncertain income tax positions	1	—	—	—	—	—	—	—	—
AFUDC — Equity	22	—	5	3	5	9	6	1	2
Non-service net periodic benefit cost	5	—	—	—	—	—	—	—	—
Other	8	4	3	—	—	3	1	2	1
Other, net	$467	$ 430	$ 8	$ 4	$ 5	$12	$ 7	$ 3	$ 3

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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	Three Months Ended March 31, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on NDT funds[(a)]									
Regulatory agreement units[(b)]	$46	$ 46	$ —	$ —	$ —	$—	$ —	$ —	$ —
Non-regulatory agreement units	56	56	—	—	—	—	—	—	—
Net unrealized losses on NDT funds									
Regulatory agreement units[(b)]	(75)	(75)	—	—	—	—	—	—	—
Non-regulatory agreement units	(96)	(96)	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities[(c)]	24	24	—	—	—	—	—	—	—
Total decommissioning-related activities	(45)	(45)	—	—	—	—	—	—	—
Investment income	4	2	—	—	—	—	—	—	—
Interest income related to uncertain income tax positions	2	1	—	—	—	—	—	—	—
AFUDC — Equity	18	—	6	2	4	6	5	1	—
Non-service net periodic benefit cost	(10)	—	—	—	—	—	—	—	—
Other	3	(2)	2	—	—	5	3	1	1
Other, net	$(28)	$ (44)	$ 8	$ 2	$ 4	$11	$ 8	$ 2	$ 1

(a) Realized income includes interest, dividends and realized gains and losses on sales of NDT fund investments.

(b) Net realized and unrealized gains (losses) related to Generation’s NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities in Exelon’s Consolidated Balance Sheets and Noncurrent payables to affiliates in Generation’s Consolidated Balance Sheets.

(c) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 15 — Asset Retirement Obligations of the Exelon 2018 Form 10-K for additional information regarding the accounting for nuclear decommissioning.

The following utility taxes are included in revenues and expenses for the three months ended March 31, 2019 and 2018. Generation’s utility tax expense represents gross receipts tax related to its retail operations, and the Utility Registrants' utility tax expense 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.

	Three Months Ended March 31, 2019								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes	$223	$ 26	$ 62	$ 34	$ 27	$74	$ 69	$ 5	$ —

	Three Months Ended March 31, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes	$235	$ 32	$ 61	$ 33	$ 26	$83	$ 77	$ 6	$ —

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants’ Consolidated Statements of Cash Flows for the three months ended March 31, 2019 and 2018.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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	Three Months Ended March 31, 2019								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Depreciation, amortization and accretion									
Property, plant and equipment[(a)]	$917	$ 392	$ 219	$ 74	$85	$127	$ 58	$35	$ 25
Amortization of regulatory assets[(a)]	143	—	32	7	51	53	36	11	6
Amortization of intangible assets, net[(a)]	15	13	—	—	—	—	—	—	—
Nuclear fuel[(c)]	261	261	—	—	—	—	—	—	—
ARO accretion[(d)]	124	123	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$1,460	$ 789	$ 251	$ 81	$136	$180	$ 94	$46	$ 31

	Three Months Ended March 31, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Depreciation, amortization and accretion									
Property, plant and equipment[(a)]	$926	$ 436	$ 201	$ 68	$82	$117	$ 53	$32	$ 23
Amortization of regulatory assets[(a)]	152	—	27	7	52	66	43	13	10
Amortization of intangible assets, net[(a)]	13	12	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities[(b)]	3	3	—	—	—	—	—	—	—
Nuclear fuel[(c)]	287	287	—	—	—	—	—	—	—
ARO accretion[(d)]	120	120	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$1,501	$ 858	$ 228	$ 75	$134	$183	$ 96	$45	$ 33

(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.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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	Three Months Ended March 31, 2019								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other non-cash operating activities:									
Pension and non-pension postretirement benefit costs	$106	$ 31	$ 24	$ 2	$15	$23	$6	$4	$4
Loss from equity method investments	6	6	—	—	—	—	—	—	—
Provision for uncollectible accounts	43	—	9	16	8	10	4	4	2
Stock-based compensation costs	28	—	—	—	—	—	—	—	—
Other decommissioning-related activity[(a)]	(202)	(202)	—	—	—	—	—	—	—
Energy-related options[(b)]	37	37	—	—	—	—	—	—	—
Amortization of regulatory asset related to debt costs	3	—	—	—	—	1	—	—	—
Amortization of rate stabilization deferral	(6)	—	—	—	—	(6)	(7)	1	—
Amortization of debt fair value adjustment	(4)	(3)	—	—	—	(1)	—	—	—
Discrete impacts from EIMA and FEJA[(c)]	28	—	28	—	—	—	—	—	—
Amortization of debt costs	9	3	1	—	—	1	1	—	—
Long-term incentive plan	25	—	—	—	—	—	—	—	—
Amortization of operating ROU asset	53	34	1	—	8	9	2	2	1
Other	1	4	(7)	(2)	(4)	(2)	(3)	—	(2)
Total other non-cash operating activities	$127	$ (90)	$ 56	$ 16	$27	$35	$3	$11	$5
Non-cash investing and financing activities:									
Change in capital expenditures not paid	$(229)	$ (93)	$ (80)	$ 8	$2	$(55)	$(15)	$(17)	$(24)
Change in PPE related to ARO update	301	301	—	—	—	—	—	—	—
Dividends on stock compensation	1	—	—	—	—	—	—	—	—

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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	Three Months Ended March 31, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other non-cash operating activities:									
Pension and non-pension postretirement benefit costs	$145	$ 51	$ 45	$ 5	$ 14	$ 15	$ 4	$ —	$ 3
Loss from equity method investments	7	7	—	—	—	—	—	—	—
Provision for uncollectible accounts	64	11	8	17	8	20	6	8	5
Stock-based compensation costs	29	—	—	—	—	—	—	—	—
Other decommissioning-related activity[(a)]	(31)	(31)	—	—	—	—	—	—	—
Energy-related options[(b)]	(7)	(7)	—	—	—	—	—	—	—
Amortization of regulatory asset related to debt costs	2	—	1	—	—	1	—	—	—
Amortization of rate stabilization deferral	7	—	—	—	—	7	1	6	—
Amortization of debt fair value adjustment	(3)	(3)	—	—	—	—	—	—	—
Discrete impacts from EIMA and FEJA[(c)]	(4)	—	(4)	—	—	—	—	—	—
Amortization of debt costs	9	3	1	—	—	1	—	—	—
Provision for excess and obsolete inventory	13	12	1	—	—	—	—	—	—
Other	9	2	(6)	(1)	(2)	9	(1)	5	1
Total other non-cash operating activities	$240	$ 45	$ 46	$ 21	$ 20	$ 53	$ 10	$ 19	$ 9
Non-cash investing and financing activities:									
Change in capital expenditures not paid	$(177)	$ (131)	$ (48)	$ (25)	$ (11)	$ 61	$ 19	$ 14	$ 27
Change in PPE related to ARO update	32	32	—	—	—	—	—	—	—
Dividends on stock compensation	1	—	—	—	—	—	—	—	—

(a) Includes the elimination of decommissioning-related activity 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 15 — Asset Retirement Obligations of the Exelon 2018 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 in Operating revenues and expenses.

(c) Reflects the change in ComEd's distribution and energy efficiency formula rates. See Note 6 — Regulatory Matters for additional information.

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

March 31, 2019	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Cash and cash equivalents	$880	$ 537	$ 68	$ 41	$ 12	$ 33	$ 11	$ 7	$ 6
Restricted cash	223	139	17	6	4	39	35	1	3
Restricted cash included in other long-term assets	211	—	193	—	—	19	—	—	19
Total cash, cash equivalents and restricted cash	$1,314	$ 676	$ 278	$ 47	$ 16	$ 91	$ 46	$ 8	$ 28

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December 31, 2018	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
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
March 31, 2018	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Cash and cash equivalents	$787	$ 610	$ 70	$ 21	$ 22	$43	$ 15	$ 7	$ 10
Restricted cash	209	127	9	5	2	40	33	—	7
Restricted cash included in other long-term assets	103	—	83	—	—	20	—	—	20
Total cash, cash equivalents and restricted cash	$1,099	$ 737	$ 162	$ 26	$ 24	$103	$ 48	$ 7	$ 37
December 31, 2017	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Cash and cash equivalents	$898	$ 416	$ 76	$ 271	$ 17	$30	$ 5	$ 2	$ 2
Restricted cash	207	138	5	4	1	42	35	—	6
Restricted cash included in other long-term assets	85	—	63	—	—	23	—	—	23
Total cash, cash equivalents and restricted cash	$1,190	$ 554	$ 144	$ 275	$ 18	$95	$ 40	$ 2	$ 31

For additional information on restricted cash see Note 1 — Significant Accounting Policies of the Exelon 2018 Form 10-K.

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants as of March 31, 2019 and December 31, 2018.

March 31, 2019	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Property, plant and equipment:									
Accumulated depreciation and amortization	$23,695 (a)	$ 12,663 (a)	$4,833	$3,598	$3,670	$930	$3,392	$1,354	$1,154
Accounts receivable:									
Allowance for uncollectible accounts	$340	$ 87	$97	$72	$27	$57	$23	$15	$19
December 31, 2018	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Property, plant and equipment:									
Accumulated depreciation and amortization	$22,902 (b)	$ 12,206 (b)	$4,684	$3,561	$3,633	$841	$3,354	$1,329	$1,137
Accounts receivable:									
Allowance for uncollectible accounts	$319	$ 104	$81	$61	$20	$53	$21	$13	$19

(a) Includes accumulated amortization of nuclear fuel in the reactor core of $3,040 million.
(b) Includes accumulated amortization of nuclear fuel in the reactor core of $2,969 million.

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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. ComEd, BGE, Pepco and DPL purchase receivables at a discount to recover primarily uncollectible accounts expense from the suppliers. PECO and ACE purchase receivables at face value and recover uncollectible accounts expense, including those from alternative retail electric and natural gas supplies, through base distribution rates and a rate rider, respectively. Exelon and the Utility Registrants do not record unbilled commodity receivables under their POR programs. Purchased billed receivables are recorded on a net basis in Exelon’s and the Utility Registrant's Consolidated Statements of Operations and Comprehensive Income and are classified in Other accounts receivable, net in their Consolidated Balance Sheets. The following tables provide information about the purchased receivables of those companies as of March 31, 2019 and December 31, 2018.

March 31, 2019	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Purchased receivables	$ 332	$ 105	$ 77	$ 65	$ 85	$ 58	$ 8	$ 19
Allowance for uncollectible accounts[(a)]	(38)	(19)	(6)	(4)	(9)	(5)	(1)	(3)
Purchased receivables, net	$ 294	$ 86	$ 71	$ 61	$ 76	$ 53	$ 7	$ 16
December 31, 2018	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Purchased receivables	$ 313	$ 94	$ 74	$ 61	$ 84	$ 57	$ 8	$ 19
Allowance for uncollectible accounts[(a)]	(34)	(17)	(5)	(3)	(9)	(5)	(1)	(3)
Purchased receivables, net	$ 279	$ 77	$ 69	$ 58	$ 75	$ 52	$ 7	$ 16

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(a) For ComEd, BGE, Pepco and DPL, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through a rate rider. BGE, Pepco and DPL recover actual write-offs which are reflected in the POR discount rate.

18. 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 ISO-NY.
- ERCOT represents operations within Electric Reliability Council of Texas.
- Other Power Regions:
  - New England represents the operations within ISO-NE.

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- South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM.
- West represents operations in the WECC, which includes California ISO.
- Canada represents operations across the entire country of Canada and includes AESO, OIESO and the Canadian portion of MISO.

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

During the first quarter of 2019, due to a change in economics in our New England region, Generation changed the way that information is reviewed by the CODM. The New England region is no longer regularly reviewed as a separate region by the CODM nor is it presented separately in any external information presented to third parties. Information for the New England region is reviewed by the CODM as part of Other Power Regions. Exelon and Generation retrospectively applied this change.

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the three months ended March 31, 2019 and 2018 is as follows:

Three Months Ended March 31, 2019 and 2018

	Generation[a]	ComEd	PECO	BGE	PHI	Other[b]	Intersegment Eliminations	Exelon
Operating revenues[c]:								
2019								
Competitive businesses electric revenues	$ 4,337	$—	$ —	$—	$—	$ —	$ (315)	$4,022
Competitive businesses natural gas revenues	879	—	—	—	—	—	(1)	878
Competitive businesses other revenues	80	—	—	—	—	—	(1)	79
Rate-regulated electric revenues	—	1,408	620	658	1,153	—	(8)	3,831
Rate-regulated natural gas revenues	—	—	280	318	71	—	(4)	665
Shared service and other revenues	—	—	—	—	4	455	(457)	2
Total operating revenues	$ 5,296	$1,408	$ 900	$976	$1,228	$ 455	$ (786)	$9,477

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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	Generation[a]	ComEd	PECO	BGE	PHI	Other[b]	Intersegment Eliminations	Exelon
2018								
Competitive businesses electric revenues	$ 4,509	$—	$—	$—	$—	$—	$ (391)	$4,118
Competitive businesses natural gas revenues	955	—	—	—	—	—	(8)	947
Competitive businesses other revenues	48	—	—	—	—	—	—	48
Rate-regulated electric revenues	—	1,512	634	658	1,169	—	(18)	3,955
Rate-regulated natural gas revenues	—	—	232	319	78	—	(4)	625
Shared service and other revenues	—	—	—	—	4	451	(455)	—
Total operating revenues	$ 5,512	$1,512	$866	$977	$1,251	$451	$ (876)	$9,693
Intersegment revenues[d]:								
2019	$ 317	$4	$1	$6	$4	$453	$ (785)	$—
2018	400	14	2	6	4	450	(876)	—
Depreciation and amortization:								
2019	$ 405	$251	$81	$136	$180	$22	$ —	$1,075
2018	448	228	75	134	183	23	—	1,091
Operating expenses:								
2019	$ 4,963	$1,135	$678	$756	$1,054	$459	$ (783)	$8,262
2018	5,218	1,223	724	800	1,125	444	(886)	8,648
Interest expense, net:								
2019	$ 111	$87	$33	$29	$65	$78	$ —	$403
2018	101	89	33	25	63	60	—	371
Income (loss) before income taxes:								
2019	$ 652	$197	$193	$196	$122	$(78)	$ —	$1,282
2018	202	211	111	156	74	(52)	—	702
Income Taxes:								
2019	$ 224	$40	$25	$36	$5	$(20)	$ —	$310
2018	9	46	(2)	28	9	(31)	—	59
Net income (loss):								
2019	$ 422	$157	$168	$160	$117	$(58)	$ —	$966
2018	186	165	113	128	65	(21)	—	636
Capital Expenditures								
2019	$ 511	$503	$222	$258	$358	$21	$ —	$1,873
2018	628	531	217	224	258	22	—	1,880
Total assets:								
March 31, 2019	$ 48,682	$31,582	$10,956	$9,967	$22,294	$8,325	$ (10,213)	$121,593
December 31, 2018	47,556	31,213	10,642	9,716	21,984	8,355	(9,800)	119,666

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(a) Intersegment revenues for Generation in 2019 include revenue from sales to PECO of $45 million, sales to BGE of $76 million, sales to Pepco of $70 million, sales to DPL of $23 million and sales to ACE of $8 million in the Mid-Atlantic region, and sales to ComEd of $94 million in the Midwest region, which eliminate upon consolidation. Intersegment revenues for Generation in 2018 include revenue from sales to PECO of $37 million, sales to BGE of $65 million, sales to Pepco of $52 million, sales to DPL of $46 million and sales to ACE of $6 million in the Mid-Atlantic region, and sales to ComEd of $194 million in the Midwest region, which eliminate upon consolidation.

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

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

(d) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation’s sale of certain products and services by and between Exelon’s segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in Operating revenues in the Consolidated Statements of Operations and Comprehensive Income.

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PHI:

	Pepco	DPL	ACE	Other[b]	Intersegment Eliminations	PHI
Operating revenues[a]:						
2019						
Rate-regulated electric revenues	$575	$310	$273	$—	$ (5)	$1,153
Rate-regulated natural gas revenues	—	70	—	—	1	71
Shared service and other revenues	—	—	—	106	(102)	4
Total operating revenues	$575	$380	$273	$106	$ (106)	$1,228
2018						
Rate-regulated electric revenues	$557	$306	$310	$—	$ (4)	$1,169
Rate-regulated natural gas revenues	—	78	—	—	—	78
Shared service and other revenues	—	—	—	113	(109)	4
Total operating revenues	$557	$384	$310	$113	$ (113)	$1,251
Intersegment revenues:						
2019	$2	$2	$1	$105	$ (106)	$4
2018	2	2	1	112	(113)	4
Depreciation and amortization:						
2019	$94	$46	$31	$10	$ (1)	$180
2018	96	45	33	9	—	183
Operating expenses:						
2019	$491	$308	$252	$108	$ (105)	$1,054
2018	501	335	287	114	(112)	1,125
Interest expense, net:						
2019	$34	$15	$14	$3	$ (1)	$65
2018	31	13	16	2	1	63
Income (loss) before income taxes:						
2019	$57	$60	$10	$113	$ (118)	$122
2018	33	38	8	64	(69)	74
Income Taxes:						
2019	$2	$7	$—	$(4)	$ —	$5
2018	2	7	1	(1)	—	9
Net income (loss):						
2019	$55	$53	$10	$(5)	$ 4	$117
2018	31	31	7	(8)	4	65
Capital Expenditures						
2019	$144	$78	$128	$8	$ —	$358
2018	127	65	63	3	—	258
Total assets:						
March 31, 2019	$8,420	$4,660	$3,783	$10,909	$ (5,478)	$22,294
December 31, 2018	8,299	4,588	3,699	10,819	(5,421)	21,984

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

(b)

Other primarily includes PHI’s corporate operations, shared service entities and other financing and investment activities.

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

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factors. For Generation, the disaggregation of revenues reflects Generation's two primary products of power sales and natural gas sales, with further disaggregation of power sales provided by geographic region. For the Utility Registrants, the disaggregation of revenues reflects the two primary utility services of rate-regulated electric sales and rate-regulated natural gas sales (where applicable), with further disaggregation of these tariff sales provided by major customer groups. Exelon's disaggregated revenues are consistent with Generation and the Utility Registrants, but exclude any intercompany revenues.

Competitive Business Revenues (Generation):

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

	Three Months Ended March 31, 2018				
	Revenues from external customers[a]			Intersegment revenues	Total Revenues
	Contracts with customers	Other[b]	Total		
Mid-Atlantic	$1,355	$ 80	$1,435	$ 5	$ 1,440
Midwest	1,273	71	1,344	2	1,346
New York	439	(29)	410	(1)	409
ERCOT	149	59	208	1	209
Other Power Regions	935	177	1,112	(32)	1,080
Total Competitive Businesses Electric Revenues	4,151	358	4,509	(25)	4,484
Competitive Businesses Natural Gas Revenues	522	433	955	25	980
Competitive Businesses Other Revenues[c]	134	(86)	48	—	48
Total Generation Consolidated Operating Revenues	$4,807	$ 705	$5,512	$ —	$ 5,512

(a) Includes all wholesale and retail electric sales to third parties and affiliated sales to the Utility Registrants.
(b) Includes revenues from derivatives and leases.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Includes unrealized mark-to-market losses of $52 million and $98 million in 2019 and 2018, respectively, and elimination of intersegment revenues.

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

	Three Months Ended March 31, 2019			Three Months Ended March 31, 2018		
	RNF from external customers[a]	Intersegment RNF	Total RNF	RNF from external customers[a]	Intersegment RNF	Total RNF
Mid-Atlantic	$679	$ 4	$683	$836	$ 14	$850
Midwest	769	2	771	847	13	860
New York	262	3	265	282	1	283
ERCOT	98	(24)	74	106	(70)	36
Other Power Regions	174	(18)	156	279	(43)	236
Total Revenues net of purchased power and fuel for Reportable Segments	1,982	(33)	1,949	2,350	(85)	2,265
Other[b]	109	33	142	(131)	85	(46)
Total Generation Revenues net of purchased power and fuel expense	$2,091	$ —	$2,091	$2,219	$ —	$2,219

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(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 losses of $28 million and $266 million in 2019 and 2018, respectively, accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 — Early Plant Retirements of $5 million and $15 million decrease to RNF in 2019 and 2018, respectively, and the elimination of intersegment RNF.

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

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

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	Three Months Ended March 31, 2018						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$717	$403	$393	$610	$259	$191	$160
Small commercial & industrial	385	101	68	115	32	46	37
Large commercial & industrial	152	58	106	259	190	23	46
Public authorities & electric railroads	14	8	7	14	7	4	3
Other(a)	230	62	78	156	49	41	66
Total rate-regulated electric revenues(b)	$1,498	$632	$652	$1,154	$537	$305	$312
Rate-regulated natural gas revenues							
Residential	$—	$161	$224	$47	$—	$47	$—
Small commercial & industrial	—	62	34	18	—	18	—
Large commercial & industrial	—	1	47	4	—	4	—
Transportation	—	6	—	5	—	5	—
Other(c)	—	2	27	4	—	4	—
Total rate-regulated natural gas revenues(d)	$—	$232	$332	$78	$—	$78	$—
Total rate-regulated revenues from contracts with customers	$1,498	$864	$984	$1,232	$537	$383	$312
Other revenues							
Revenues from alternative revenue programs	$5	$(1)	$(13)	$18	$19	$1	$(2)
Other rate-regulated electric revenues(e)	9	3	4	1	1	—	—
Other rate-regulated natural gas revenues(e)	—	—	2	—	—	—	—
Total other revenues	$14	$2	$(7)	$19	$20	$1	$(2)
Total rate-regulated revenues for reportable segments	$1,512	$866	$977	$1,251	$557	$384	$310

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

(b) Includes operating revenues from affiliates of $4 million, $1 million, $2 million, $3 million, $2 million, $2 million and $1 million at ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, in 2019 and $14 million, $2 million, $2 million, $4 million $2 million, $2 million and 1 million at ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, in 2018.

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

(d) Includes operating revenues from affiliates of less than $1 million and $4 million at PECO and BGE, respectively, in 2019 and 2018.

(e) Includes late payment charge revenues.

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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. During the first quarter of 2019, due to a change in economics in our New England region, Generation is changing the way that information is reviewed by the CODM. The New England region will no longer be regularly reviewed as a separate region by the CODM nor will it be presented separately in any external information presented to third parties. Information for the New England region will be reviewed by the CODM as part of Other Power Regions. As a result, beginning in the first quarter of 2019, Generation will disclose five reportable segments consisting of Mid-Atlantic, Midwest, New York, ERCOT and Other Power Regions. See Note 1 — Significant Accounting Policies and Note 18 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's principal subsidiaries and reportable segments.
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. Additionally, the results of Exelon’s corporate operations include interest costs and income from various investment and financing activities.
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.

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Financial Results of Operations

GAAP Results of Operations. The following table sets forth Exelon's GAAP consolidated Net Income attributable to common shareholders by Registrant for the three months ended March 31, 2019 compared to the same period in 2018. For additional information regarding the financial results for the three months ended March 31, 2019 and 2018 see the discussions of Results of Operations by Registrant.

	Three Months Ended March 31,		Favorable (unfavorable) variance
	2019	2018	
Exelon	$907	$585	$ 322
Generation	363	136	227
ComEd	157	165	(8)
PECO	168	113	55
BGE	160	128	32
PHI	117	65	52
Pepco	55	31	24
DPL	53	31	22
ACE	10	7	3
Other[(a)]	(58)	(22)	(36)

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

Three Months Ended March 31, 2019 Compared to Three Months Ended March 31, 2018. Net income attributable to common shareholders increased by $322 million and diluted earnings per average common share increased to $0.93 in 2019 from $0.60 in 2018 primarily due to:

- Net unrealized gains on NDT funds in 2019 compared to losses in 2018;
- Decreased mark-to-market losses;
- A benefit associated with the remeasurement of the TMI ARO;
- Increased capacity prices;
- Regulatory rate increases at PECO, BGE, Pepco and DPL; and
- Lower storms costs at PECO and BGE.

The increases were partially offset by:

- Lower realized energy prices and
- The absence of the revenue recognized in the first quarter 2018 related to ZECs generated in Illinois from June through December 2017.

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

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be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following tables provide a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the three months ended March 31, 2019 compared to the same period in 2018.

	Three Months Ended March 31,			
	2019		2018	
(All amounts in millions after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$907	$ 0.93	$585	$ 0.60
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $12 and $69, respectively)	31	0.03	197	0.20
Unrealized Losses (Gains) Related to NDT Fund Investments[(a)] (net of taxes of $161 and $45, respectively)	(193)	(0.20)	66	0.07
PHI Merger and Integration Costs (net of taxes of $1)	—	—	3	—
Long-Lived Asset Impairments (net of taxes of $1)	4	—	—	—
Plant Retirements and Divestitures[(b)] (net of taxes of $6 and $32, respectively)	19	0.02	92	0.10
Cost Management Program[(c)] (net of taxes of $3 and $1, respectively)	11	0.01	5	0.01
Noncontrolling Interests[(d)] (net of taxes of $13 and $5, respectively)	67	0.07	(23)	(0.02)
Adjusted (non-GAAP) Operating Earnings	$846	$ 0.87	$925	$ 0.96

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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 2018 and 2017 ranged from 26.0 percent to 29.0 percent. Under IRS regulations, NDT fund investment returns are taxed at different rates for investments if they are in qualified or non-qualified funds.The effective tax rates for the unrealized gains and losses related to NDT fund investments were 45.4 percent and 40.3 percent for the three months ended March 31, 2019 and 2018, respectively.

(a) Reflects the impact of net unrealized gains and losses on Generation's NDT fund investments for Non-Regulatory and Regulatory Agreement Units. The impacts of the Regulatory Agreement Units, including the associated income taxes, are contractually eliminated, resulting in no earnings impact.

(b) In 2018, primarily reflects accelerated depreciation and amortization expenses and one-time charges associated with Generation's decision to early retire the Oyster Creek nuclear facility and accelerated depreciation and amortization expenses associated with the 2017 decision to early retire the TMI nuclear facility, partially offset by a gain associated with Generation's sale of its electrical contracting business. In 2019, primarily reflects accelerated depreciation and amortization expenses associated with Generation's previous decision to early retire the TMI nuclear facility and a benefit associated with a remeasurement of the TMI ARO.

(c) Primarily represents reorganization costs related to cost management programs.

(d) Represents elimination from Generation's results of the noncontrolling interests related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments at CENG.

Significant 2019 Transactions and Developments

Utility Rates and Base Rate Proceedings

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

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The following tables show the Utility Registrants' completed and pending distribution base rate case proceedings in 2019. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on other regulatory proceedings.

Completed Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement Increase	Approved Revenue Requirement Increase (Decrease)	Approved ROE	Approval Date	Rate Effective Date
BGE - Maryland (Natural Gas)	June 8, 2018 (amended October 12, 2018)	$ 61	$ 43	9.8 %	January 4, 2019	January 4, 2019
ACE - New Jersey (Electric)	August 21, 2018 (amended November 19, 2018)	$ 122	$ 70	9.6 %	March 13, 2019	April 1, 2019

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
Pepco - Maryland (Electric)	January 15, 2019 (amended April 30, 2019)	$ 27	10.3 %	Third quarter of 2019
ComEd - Illinois (Electric)	April 8, 2019	$ (6)	8.91 %	December 2019

PECO Transmission Formula Rate

On May 1, 2017, PECO filed a request with FERC seeking approval to update its transmission rates and change the manner in which PECO's transmission rate is determined from a fixed rate to a formula rate. The formula rate will be updated annually to ensure that under this rate customers pay the actual costs of providing transmission services. The formula rate filing includes a requested increase of $22 million to PECO's annual transmission revenues and a requested rate of return on common equity of 11%, inclusive of a 50 basis point adder for being a member of a regional transmission organization. PECO requested that the new transmission rate be effective as of July 2017. On June 27, 2017, FERC issued an Order accepting the filing and suspending the proposed rates until December 1, 2017, subject to refund, and set the matter for hearing and settlement judge procedures. On May 4, 2018, the Chief Administrative Law Judge terminated settlement judge procedures and designated a new presiding judge. On February 8, 2019, PECO and the active parties reached an agreement in principle to settle this case. The presiding Administrative Law Judge has since suspended the procedural schedule in order for PECO and the active parties to continue working towards finalizing a settlement. On April 15, 2019, PECO and the active parties filed a status update with the presiding Administrative Law Judge requesting an additional 45 days to file a settlement. PECO cannot predict the outcome of this proceeding, or the transmission formula FERC may approve.

On May 11, 2018, pursuant to the transmission formula rate request discussed above, PECO made its first annual formula rate update, which included a revenue decrease of $6 million. The revenue decrease of $6 million included an approximately $20 million reduction as a result of the tax savings associated with the TCJA. The updated transmission rate was effective June 1, 2018, subject to refund.

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Pacific Gas & Electric Bankruptcy

Generation’s Antelope Valley, a 242 MW solar facility in Lancaster, CA, 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. As of March 31, 2019, Generation had approximately $750 million and $500 million of net long-lived assets and nonrecourse debt outstanding, respectively, related to Antelope Valley. PG&E’s bankruptcy created an event of default for Antelope Valley’s nonrecourse debt that provides the lender with a right to accelerate amounts outstanding under the loan such that they would become immediately due and payable. As a result of the ongoing event of default and the absence of a waiver from the lender foregoing their acceleration rights, the debt was reclassified as current in Exelon’s and Generation’s Consolidated Balance Sheets as of March 31, 2019.

Generation assessed and determined that Antelope Valley’s long-lived assets were not impaired as of March 31, 2019. Significant changes in assumptions such as the likelihood of the PPA being rejected as part of the bankruptcy proceedings could potentially result in future impairments of Antelope Valley's net long-lived assets, which could be material. Generation is monitoring the bankruptcy proceedings for any changes in circumstances that would indicate the carrying amount of the net long-lived assets of Antelope Valley may not be recoverable.

See Note 7 — Impairment of Long-Lived Assets and Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the PG&E bankruptcy.

Early Plant Retirements

Oyster Creek. Generation permanently ceased generation operations at Oyster Creek in September 2018. On July 31, 2018 Generation entered into an agreement with Holtec International and its wholly owned subsidiary, Oyster Creek Environmental Protection, LLC, for the sale and decommissioning of Oyster Creek. Generation currently anticipates satisfaction of the closing conditions for the transaction to occur in the second half of 2019. See Note 3 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Three Mile Island. On May 30, 2017, Generation announced it will permanently cease generation operations at TMI on or about September 30, 2019. The plant is currently committed to operate through May 2019. As a result of the previous decision to early retire TMI, Exelon and Generation recorded a $4 million incremental pre-tax net benefit for the three months ended March 31, 2019 primarily due to a benefit associated with the remeasurement of the TMI ARO, partially offset by accelerated depreciation of the plant assets. For the full year ended December 31, 2019, Exelon and Generation estimate approximately $155 million of incremental pre-tax net non-cash charges associated with the early retirement of TMI, primarily due to accelerated depreciation of the plant assets.

Salem. In 2017, PSEG announced that its New Jersey nuclear plants, including Salem, of which Generation owns a 42.59% ownership interest, were showing increased signs of economic distress, which could lead to an early retirement. PSEG is the operator of Salem and also has the decision making authority to retire Salem. In 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. On April 18, 2019, the NJBPU approved the award of ZECs to Salem 1 and Salem 2. Assuming the New Jersey ZEC program operates as expected, Generation no longer considers Salem to be at heightened risk for early retirement.

Dresden, Byron and Braidwood. Generation’s Dresden, Byron and Braidwood nuclear plants in Illinois are also showing increased signs of economic distress, which could lead to an early retirement, in a market that does not currently compensate them for their unique contribution to grid resiliency and their ability to produce large amounts of energy without carbon and air pollution. The May 2018 PJM capacity auction for the 2021-2022 planning year resulted in the largest volume of nuclear capacity ever not selected in the auction, including all of Dresden, and portions of Byron and Braidwood. Exelon continues to work with stakeholders on state policy solutions, while also advocating for broader market reforms at the regional and federal level.

See Note 6 — Regulatory Matters, Note 8 — Early Plant Retirements and Note 13 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional information.

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Exelon’s Strategy and Outlook for 2019 and Beyond

Exelon’s value proposition and competitive advantage come from its scope and its core strengths of operational excellence and financial discipline. Exelon leverages its integrated business model to create value. Exelon’s regulated and competitive businesses feature a mix of attributes that, when combined, offer shareholders and customers a unique value proposition:

- The Utility Registrants provide a foundation for steadily growing earnings, which translates to a stable currency in our stock.
- Generation’s competitive businesses provide free cash flow to invest primarily in the utilities and in long-term, contracted assets and to reduce debt.

Exelon believes its strategy provides a platform for optimal success in an energy industry experiencing fundamental and sweeping change.

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

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

Exelon’s financial priorities are to maintain investment grade credit metrics at each of the Registrants, to maintain optimal capital structure and to return value to Exelon’s shareholders with an attractive dividend throughout the energy commodity market cycle and through stable earnings growth. Exelon's Board of Directors has approved a dividend policy providing a raise of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

Various market, financial, regulatory, legislative and operational factors could affect the Registrants' success in pursuing their strategies. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these issues. One key issue is ensuring the ability to properly value nuclear generation assets in the market, solutions to which Exelon is actively pursuing in a variety of jurisdictions and venues. See ITEM 1A. RISK FACTORS of the Exelon 2018 Form 10-K for additional information regarding market and financial factors.

Continually optimizing the cost structure is a key component of Exelon’s financial strategy. In August 2015, Exelon announced a cost management program focused on cost savings of approximately $400 million at BSC and Generation, which was fully realized in 2018. Approximately 75% of the savings were related to Generation, with the remaining amount related to the Utility Registrants. In November 2017, Exelon announced a commitment for an additional $250 million of cost savings, primarily at Generation, to be achieved by 2020. In November 2018, Exelon announced the elimination of an approximately additional $200 million of annual ongoing costs, through initiatives primarily at Generation and BSC, by 2021. Approximately $150 million is expected to be related to Generation, with the remaining amount related to the Utility Registrants. These actions are in response to the continuing economic challenges confronting all parts of Exelon’s business and industry, necessitating continued focus on cost management through enhanced efficiency and productivity.

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Growth Opportunities
Management continually evaluates growth opportunities aligned with Exelon’s businesses, assets and markets, leveraging Exelon’s expertise in those areas and offering sustainable returns.
Regulated Energy Businesses. The Utility Registrants anticipate investing approximately $29 billion over the next five years in electric and natural gas infrastructure improvements and modernization projects, including smart meter and smart grid initiatives, storm hardening, advanced reliability technologies, and transmission projects, which is projected to result in an increase to current rate base of approximately $13 billion by the end of 2023. The Utility Registrants invest in rate base where beneficial to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. These investments are made at the lowest reasonable cost to customers.
See Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements Exelon 2018 Form 10-K for additional information on the Smart Meter and Smart Grid Initiatives and infrastructure development and enhancement programs.
Competitive Energy Businesses. Generation continually assesses the optimal structure and composition of its generation assets as well as explores wholesale and retail opportunities within the power and gas sectors. Generation’s long-term growth strategy is to ensure appropriate valuation of its generation assets, in part through public policy efforts, identify and capitalize on opportunities that provide generation to load matching as a means to provide stable earnings, and identify emerging technologies where strategic investments provide the option for significant future growth or influence in market development.
Liquidity Considerations
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.). The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.
Exelon Corporate, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE have unsecured syndicated revolving credit facilities. Generation also has bilateral credit facilities. Refer to Note 13 — Debt and Credit Agreements of the Exelon 2018 Form 10-K for additional information on credit facilities.
For additional information regarding the Registrants' liquidity for the three months ended March 31, 2019, see Liquidity and Capital Resources discussion below.
Project Financing
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 13 — Debt and Credit Agreements of the Exelon 2018 Form 10-K for additional information on nonrecourse debt and Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Pacific Gas and Electric Company bankruptcy.

Other Key Business Drivers and Management Strategies
Power Markets
Price of Fuels
The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon’s revenues. Forward natural gas prices have declined significantly over the last several years; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).
Complaints and PJM Filing at FERC Seeking to Mitigate ZEC Programs
PJM and NYISO capacity markets include a Minimum Offer Price Rule (MOPR) that is intended to preclude buyers from exercising buyer market power. If a resource is subjected to a MOPR, its offer is adjusted to effectively remove the revenues it receives through a government-provided financial support program - resulting in a higher offer that may not clear the capacity market. Currently, the MOPRs in PJM and NYISO apply only to certain new gas-fired resources.
On January 9, 2017, EPSA filed two requests with FERC: one seeking to amend a prior complaint against PJM and another seeking expedited action on a pending NYISO compliance filing in an existing proceeding. A similar complaint also against PJM was filed at FERC on May 31, 2018. These complaints generally allege that the relevant MOPR should be expanded to also apply to existing resources including those receiving ZEC compensation under the New Jersey ZEC, New York CES and Illinois ZES programs. Exelon filed protests at FERC in response to each filing, arguing generally that ZEC payments provide compensation for an environmental attribute that is distinct from the energy and capacity sold in the FERC-jurisdictional markets, and therefore, are no different than other renewable support programs like the PTC and RPS programs that have generally not been subject to a MOPR. However, if successful, for Generation’s facilities in PJM and NYISO that are currently receiving ZEC compensation (Quad Cities, Ginna, Fitzpatrick, Nine Mile Point and Salem, of which Generation owns a 42.59% interest), an expanded MOPR could require exclusion of ZEC compensation when bidding into future capacity auctions such that these facilities would have an increased risk of not clearing in future capacity auctions and thus no longer receiving capacity revenues during the respective ZEC programs. Any mitigation of these generating resources could have a material effect on Exelon’s and Generation’s future cash flows and results of operations.
In June 2018, FERC addressed one of the MOPR complaints involving PJM and concluded based on that complaint and a related PJM filing that PJM’s existing tariff allows resources receiving out-of-market support to affect capacity prices in a manner that will cause unjust and unreasonable and unduly discriminatory rates in PJM regardless of the intent motivating the support. FERC suggested that modifying two elements of PJM’s existing tariff could produce a just and reasonable replacement and asked for initial comments on its proposal by August 28, 2018, later extended to October 2, 2018. First, FERC found that an expansion of the current MOPR mechanism to cover all existing generating resources, regardless of resource type, including those receiving either ZEC or REC compensation, could protect the capacity markets from unwanted price suppression. Second, FERC preliminarily found that a modified version of PJM’s existing Fixed Resource Requirement (FRR) option could enable state subsidized resources and a corresponding amount of load to be removed from the capacity market, thereby alleviating their price suppressive effects on capacity clearing prices. Under this alternative, state supported generating resources would potentially be compensated through mechanisms other than through PJM’s existing market mechanism. FERC established March 21, 2016 as the refund effective date and also allowed PJM to delay its next capacity auction from May 2019 to August 2019 to allow parties time to develop and file proposals in the FERC proceeding, FERC time to determine the appropriate solution and PJM time to implement FERC's solution. On October 2, 2018, Exelon, along with several ratepayer advocates, environmental organizations and other nuclear generators, submitted shared principles supporting a workable new FRR mechanism (as suggested by FERC) and detailing how such a mechanism should be implemented. Exelon also submitted individual comments covering matters not addressed in the shared principles. FERC has not yet issued a decision on the second MOPR complaint involving PJM or the MOPR complaint involving NYISO. On April 10, 2019, PJM notified FERC of its intent to proceed with the next capacity auction in August 2019 under the existing market rules and asked FERC to clarify that it would not require PJM to re-run the auction in the event FERC alters those market rules in its decision on the MOPR complaint. It is too early to predict the final

outcome of each of these proceedings or their potential financial impact, if any, on Exelon or Generation.

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Complaint at FERC Seeking to Alter Capacity Market Default Offer Caps

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

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, as amended, (the Act) from imports of uranium products, alleging that these imports threaten national security (the Petition). The Act was promulgated by Congress to protect essential national security industries whose survival is threatened by imports. As such, the Act authorizes the Secretary of Commerce (the Secretary) to conduct investigations to evaluate the effects of imports of any item on the national security of the U.S. The Petition alleges that the loss of a viable U.S. uranium mining industry would have a significant detrimental impact on the national, energy, and economic security of the U.S. and the ability of the country to sustain an independent nuclear fuel cycle. On July 18, 2018, the Secretary announced that the DOC had initiated an investigation in response to the petition. The Secretary submitted a report to President Trump on April 14, 2019. The President now has 90 days to decide whether and how to act on the Secretary's recommendations. The relief sought by the petitioners would require U.S. nuclear reactors to purchase at least 25% of their uranium needs from domestic mines for the next 10 years or more, although the President could choose this remedy or any other remedy, whether recommended by the DOC or not, or could choose to take no action. Exelon and Generation cannot currently predict the outcome of this investigation. It is reasonably possible that if this petition is successful the resulting increase in nuclear fuel costs in future periods could have a material, unfavorable impact on Exelon’s and Generation’s financial statements.

Energy Demand

Modest economic growth partially offset by energy efficiency initiatives is resulting in relatively flat load growth in electricity for the Utility Registrants. ComEd, PECO, BGE, DPL and ACE are projecting load volumes to increase (decrease) by (0.2)%, (0.3)%, 1.3%, (0.7)% and (1.9)% respectively, in 2019 compared to 2018. Pepco is projecting load volumes to be flat in 2019 compared to 2018.

Retail Competition

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

Strategic Policy Alignment

As part of its strategic business planning process, Exelon routinely reviews its hedging policy, dividend policy, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices and the impacts of hypothetical credit downgrades.

Exelon's board of directors declared first quarter 2019 dividends of $0.3625 per share on Exelon's common stock. The first quarter 2019 dividend was paid on March 8, 2019.

Exelon's board of directors declared second quarter 2019 dividends of $0.3625 per share on Exelon's common stock and is payable on June 10, 2019.

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Exelon's Board of Directors approved an updated dividend policy providing an increase of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.
All future quarterly dividends require approval by Exelon's Board of Directors.
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. Generation has hedges in place that significantly mitigate this risk for 2019 and 2020. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of March 31, 2019, the percentage of expected generation hedged is 90%-93%, 64%-67% and 38%-41% for 2019, 2020, and 2021 respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, such as wholesale and retail sales of power, options and swaps. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.
Generation procures oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is 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, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation’s procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 62% of Generation’s uranium concentrate requirements from 2019 through 2023 are supplied by three producers. 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 financial statements.
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
Exelon was actively involved in the Obama Administration’s development and implementation of environmental regulations for the electric industry, in pursuit of its business strategy to provide reliable, clean, affordable and innovative energy products. These efforts have most frequently involved air, water and waste controls for fossil-fueled electric generating units, as set forth in the discussion below. These regulations have had a disproportionate adverse impact on coal-fired power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and have resulted in the retirement of older, marginal facilities. Due to its low emission generation portfolio, Generation has not been significantly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil fuel plants.
Through the issuance of a series of Executive Orders (EO), President Trump has initiated review of a number of EPA and other regulations issued during the Obama Administration, with the expectation that the Administration will seek repeal or significant revision of these rules. Under these EOs, each executive agency is required to evaluate existing regulations and make recommendations regarding repeal, replacement, or modification. The Administration’s actions are intended to result in less stringent compliance requirements under air, water, and waste regulations. The exact nature, extent, and timing of the regulatory changes are unknown, as well as the ultimate impact on Exelon’s and its subsidiaries results of operations and cash flows.

In particular, the Administration has targeted certain existing EPA regulations for repeal, including notably the Clean Power Plan, as well as revoking many Executive Orders, reports, and guidance issued by the Obama Administration

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on the topic of climate change or the regulation of greenhouse gases. The Executive Order also disbanded the Interagency Working Group that developed the social cost of carbon used in rulemakings and withdrew all technical support documents supporting the calculation. Other regulations that are under review include the Clean Water Act rule relating to jurisdictional waters of the U.S., the Steam Electric Effluent Guidelines relating to waste water discharges from coal-fired power plants, and the 2015 National Ambient Air Quality Standard (NAAQS) for ozone. The review of final rules could extend over several years as formal notice and comment rulemaking process proceeds.

Air Quality

Mercury and Air Toxics Standard Rule (MATS). On December 16, 2011, the EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation 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. The initial compliance deadline to meet the new standards was April 16, 2015; however, facilities may have been granted an additional one or two-year extension in limited cases. Numerous entities challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. In April 2014, the D.C. Circuit Court issued an opinion 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 hazardous air pollutants emitted by electric utilities. The U.S. Supreme Court, however, did not vacate the rule; rather, it was remanded to the D.C. Circuit Court to take further action consistent with the U.S. Supreme Court’s opinion on this single issue. On April 27, 2017, the D.C. Circuit granted EPA’s motion to hold the litigation in abeyance, pending EPA’s review of the MATS rule pursuant to President Trump’s EO discussed above. Following EPA’s review and determination of its course of action for the MATS rule, the parties will have 30 days to file motions on future proceedings. Notwithstanding the Court’s order to hold the litigation in abeyance, the MATS rule remains in effect. Exelon will continue to participate in the remanded proceedings before the D.C. Circuit Court as an intervenor in support of the rule. On December 28, 2018, the EPA proposed to revoke the "appropriate and necessary" finding underpinning the MATS rule. While the proposal would leave the rule in place, it would leave it vulnerable to future legal challenge.

Clean Power Plan. On April 28, 2017, the D.C. Circuit Court issued orders in separate litigation related to the EPA’s actions under the Clean Power Plan (CPP) to amend Clean Air Act Section 111(d) regulation of existing fossil-fired electric generating units and Section 111(b) regulation of new fossil-fired electric generating units. In both cases, the Court has determined to hold the litigation in abeyance pending a determination whether the rule should be remanded to the EPA. On October 10, 2017, EPA issued a proposed rule to repeal the CPP in its entirety, based on a proposed change in the Agency’s legal interpretation of Clean Air Act Section 111(d) regarding actions that the Agency can consider when establishing the Best System of Emission Reduction (“BSER”) for existing power plants. Under the proposed interpretation, the Agency exceeded its authority under the Clean Air Act by regulating beyond individual sources of GHG emissions. Subsequently, on August 31, 2018, EPA proposed its Affordable Clean Energy Rule, which would replace the CPP with revised emission guidelines based on heat rate improvement measures that could be achieved within the fence line of existing power plants.

2015 Ozone National Ambient Air Quality Standards (NAAQS). On April 11, 2017, the D.C. Circuit ordered that the consolidated 2015 ozone NAAQS litigation be held in abeyance pending EPA’s further review of the 2015 Rule. Concurrent with its review, the Agency issued several rounds of final ozone designations for the 2015 ozone NAAQS in December 2017 and April 2018. On August 1, 2018, EPA filed a status report to the Court that indicated Agency does not intend to revise or repeal the 2015 ozone standard at this time. Subsequently the Court ordered the case reactivated.

Primary SO2 National Ambient Air Quality Standards (NAAQS). EPA took final action on April 17, 2019 to retain the current primary SO2 standard without revision, leaving the standard established in 2010 in effect.

Climate Change. Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions. In the absence of Federal legislation, the EPA is moving forward with the regulation of GHG emissions under the Clean Air Act. In addition, there have been recent developments in the international regulation of GHG emissions pursuant to the United Nations Framework Convention on Climate Change (“UNFCCC” or “Convention”). See ITEM 1. BUSINESS, "Air Quality" of the Exelon 2018 Form 10-K for additional information.

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Water Quality
Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation’s power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by recent changes to the regulations. For Generation, those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, FitzPatrick, Ginna, Gould Street, Handley, Mystic Unit 7, Nine Mile Point Unit 1, Peach Bottom, Quad Cities, and Salem. See ITEM 1. BUSINESS, "Water Quality" of the Exelon 2018 Form 10-K for additional information.
Solid and Hazardous Waste
In October 2015, the first federal regulation for the disposal of coal combustion residuals (CCR) from power plants became effective. The rule classified CCR as non-hazardous waste under RCRA, and CCR continued to be regulated by most states subject to coordination with the federal regulations. In July 2018, the EPA issued a final rule amending the 2015 rule that provides more compliance flexibility to the states and owners and operators of coal ash disposal sites. Generation currently does not own or operate any such sites subject to the CCR rule. Generation previously recorded accruals consistent with state regulation for its owned coal ash sites, and as such, the CCR rule is not expected to impact Exelon’s and Generation’s financial results. Generation does not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted under the CCR rule for coal ash disposal sites formerly owned by Generation. For these reasons, Generation is unable to predict whether and to what extent it may ultimately be held responsible for remediation and other costs relating to formerly owned coal ash disposal sites under the new regulations.
See Note 16 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information related to environmental matters, including the impact of environmental regulation.
Other Legislative and Regulatory Developments
Illinois Clean Energy Progress Act
On March 14, 2019, the Clean Energy Progress Act was introduced in the Illinois General Assembly to preserve Illinois’ clean energy choices arising from FEJA and empower the IPA to conduct capacity procurements outside of PJM’s base residual auction process, while utilizing the fixed resource requirement provisions in PJM's tariffs which are still subject to penalties and other obligations under the PJM tariffs. The most significant provisions of the proposed legislation are as follows: (1) it allows the IPA to procure capacity directly from clean energy resources that have previously sold ZECs or RECs, including certain of Generation’s nuclear plants in Illinois, or from new clean energy resources, (2) it establishes a goal of achieving 100% carbon-free power in the ComEd service territory by 2032, and (3) it implements reforms to enhance consumer protections in the state’s competitive retail electricity and natural gas markets, including Generation’s retail customers. Energy legislation has also been proposed by other stakeholders, including renewable resource developers, environmental advocates, and coal-fueled generators. Exelon and Generation are working with legislators and stakeholders and cannot predict the outcome or the potential financial impact, if any, on Exelon or Generation.
Keep Powering Pennsylvania Act
On March 11, 2019, the Keep Powering Pennsylvania Act was introduced in the Pennsylvania General Assembly to amend the Alternative Energy Portfolio Standards Act of 2004. The proposed legislation recognizes the value that all zero-emission electric generation resources provide to Pennsylvania by adding nuclear plants and certain other renewable generation resources (Tier III resources) to the zero-emission electric generation resources that currently receive alternative energy credits in Pennsylvania. Further, the proposed legislation would allow for these Tier III resources to continue to receive capacity payments at the same level as the PJM capacity auction clearing price. In order to initially qualify as a Tier III resource, a resource must make a commitment to operate for at least six years. The price of the alternative energy credits for Tier III resources is tied to the value of existing Tier I resources, with a price cap. Regulated utilities, including PECO, would be required to purchase alternative energy credits for all retail customers and allowed to recover those costs from customers. Exelon and Generation are working with legislators and stakeholders and cannot predict the outcome or the potential financial impact, if any, on Exelon or Generation.

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Nuclear Powers Act of 2019

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

Employees

During 2018, Generation finalized its CBA with the Security Officer's union at Braidwood which will expire in 2021. Exelon Utilities finalized its two ACE Local 210 contracts and both will expire in 2023. Additionally, the CBA between Exelon Nuclear Security at Clinton and the SEIU Local 1 was extended so that the matter between two rival union organizations can be resolved. An election was held, and the new union named "LEOSU" prevailed. Negotiations will begin for an initial agreement with LEOSU which could result in some modifications to wages, hours and other terms and conditions of employment. Management cannot predict the outcome of such negotiations. There was an organizing effort over approximately 18 ACE control room System Operators. While an election was held with an outcome favorable to Local 210, collective bargaining over this small segment of employees will not commence until the issue of whether the System Operators are NLRA statutory supervisors is determined, and that matter is currently before the NLRB. Negotiations continue between BGE and IBEW Local 410 for a first contract and it is not certain when negotiations will conclude but we anticipate a favorable outcome. In April 2019, the CBAs with IBEW Local 15 covering employees at BSC, ComEd and Generation, was extended through 2024. The CBA between Pepco and IBEW Local 1900 is scheduled to expire on May 26, 2019. Negotiations have begun this month and we anticipate a positive outcome.

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. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — CRITICAL ACCOUNTING POLICIES AND ESTIMATES in Exelon's, Generation's, ComEd's, PECO's, BGE's, PHI's, Pepco's, DPL's and ACE's combined 2018 Form 10-K for a discussion of the estimates and judgments necessary in the Registrants' accounting for AROs, goodwill, purchase accounting, unamortized energy contract assets and liabilities, asset impairments, depreciable lives of property, plant and equipment, defined benefit pension and other postretirement benefits, regulatory accounting, derivative instruments, taxation, contingencies, revenue recognition and allowance for uncollectible accounts. At March 31, 2019, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2018.

Results of Operations by Registrant

The Registrants' 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. For the Utility Registrants, their Operating revenues reflect the full and current recovery of commodity procurement costs given the rider mechanisms approved by their respective state regulators. The commodity procurement costs, which are recorded in Purchased power and fuel expense, and the associated revenues can be volatile. Therefore, the Utility Registrants believe that RNF is a useful measure because it excludes the effect on Operating revenues caused by the volatility in these expenses.

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Generation

Results of Operations — Generation

	Three Months Ended March 31, 2019	2018	Favorable (Unfavorable) Variance
Operating revenues	$5,296	$5,512	$ (216)
Purchased power and fuel expense	3,205	3,293	88
Revenues net of purchased power and fuel expense[(a)]	2,091	2,219	(128)
Other operating expenses			
Operating and maintenance	1,218	1,339	121
Depreciation and amortization	405	448	43
Taxes other than income	135	138	3
Total other operating expenses	1,758	1,925	167
Gain on sales of assets and businesses	—	53	(53)
Operating income	333	347	(14)
Other income and (deductions)			
Interest expense, net	(111)	(101)	(10)
Other, net	430	(44)	474
Total other income and (deductions)	319	(145)	464
Income before income taxes	652	202	450
Income taxes	224	9	(215)
Equity in losses of unconsolidated affiliates	(6)	(7)	1
Net income	422	186	236
Net income attributable to noncontrolling interests	59	50	(9)
Net income attributable to membership interest	$363	$136	$ 227

Three Months Ended March 31, 2019 Compared to Three Months Ended March 31, 2018. Net income attributable to membership interest increased by $227 million primarily due to:

- Net unrealized gains on NDT funds in 2019 compared to losses in 2018;
- Decreased mark-to-market losses;
- A benefit associated with the remeasurement of the TMI ARO; and
- Increased capacity prices.

The increases were partially offset by:

- Lower realized energy prices and
- The absence of the revenues recognized in the first quarter 2018 related to ZECs generated in Illinois from June through December 2017.

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. During the first quarter of 2019, due to a change in economics in our New England region, Generation is changing the way that information is reviewed by the CODM. The New England region will no longer be regularly reviewed as a separate region by the CODM nor will it be presented

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Generation

separately in any external information presented to third parties. Information for the New England region will be reviewed by the CODM as part of Other Power Regions. See Note 24 - Segment Information of the Combined Notes to Consolidated Financial Statements for additional information.
The following business activities are not allocated to a region and are reported under Other: natural gas, as well as other miscellaneous business activities that are not significant to overall operating revenues or results of operations. Further, the following activities are not allocated to a region and are reported in Other: accelerated nuclear fuel amortization associated with nuclear decommissioning; and other miscellaneous revenues.
Generation evaluates the operating performance of electric business activities using the measure of RNF. Operating revenues include all sales to third parties and affiliated sales to the Utility Registrants. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for owned generation and fuel costs associated with tolling agreements.
For the three months ended March 31, 2019 and 2018, RNF by region were as follows:

	Three Months Ended March 31,		Variance	% Change
	2019	2018		
Mid-Atlantic[(a)]	$683	$850	$ (167)	(19.6)%
Midwest[(b)]	771	860	(89)	(10.3)%
New York	265	283	(18)	(6.4)%
ERCOT	74	36	38	105.6 %
Other Power Regions	156	236	(80)	(33.9)%
Total electric revenue net of purchased power and fuel expense	1,949	2,265	(316)	(14.0)%
Proprietary Trading	4	6	(2)	(33.3)%
Mark-to-market losses	(28)	(266)	238	(89.5)%
Other	166	214	(48)	(22.4)%
Total revenue net of purchased power and fuel expense	$2,091	$2,219	$ (128)	(5.8)%

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

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Generation

Generation's supply sources by region are summarized below:

Supply source (GWhs)	Three Months Ended March 31, 2019	2018	Variance	% Change
Nuclear Generation				
Mid-Atlantic[(a)]	15,080	16,229	(1,149)	(7.1)%
Midwest	23,733	23,597	136	0.6 %
New York[(a)]	6,902	7,115	(213)	(3.0)%
Total Nuclear Generation	45,715	46,941	(1,226)	(2.6)%
Fossil and Renewables				
Mid-Atlantic	951	900	51	5.7 %
Midwest	392	455	(63)	(13.8)%
New York	1	1	—	— %
ERCOT	3,078	2,949	129	4.4 %
Other Power Regions	3,141	4,028	(887)	(22.0)%
Total Fossil and Renewables	7,563	8,333	(770)	(9.2)%
Purchased Power				
Mid-Atlantic	2,566	766	1,800	235.0 %
Midwest	288	336	(48)	(14.3)%
ERCOT	1,042	1,373	(331)	(24.1)%
Other Power Regions	12,569	9,570	2,999	31.3 %
Total Purchased Power	16,465	12,045	4,420	36.7 %
Total Supply/Sales by Region				
Mid-Atlantic[(b)]	18,597	17,895	702	3.9 %
Midwest[(b)]	24,413	24,388	25	0.1 %
New York	6,903	7,116	(213)	(3.0)%
ERCOT	4,120	4,322	(202)	(4.7)%
Other Power Regions	15,710	13,598	2,112	15.5 %
Total Supply/Sales by Region	69,743	67,319	2,424	3.6 %

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(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 and BGE in the Mid-Atlantic region, affiliate sales to ComEd in the Midwest region and affiliate sales to Pepco, DPL and ACE in the Mid-Atlantic region.

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Generation

For the three months ended March 31, 2019 and 2018, changes in RNF by region were as follows:

	2019 vs. 2018 Increase/ (Decrease)	Description
Mid-Atlantic	$(167)	• lower realized energy prices • decreased revenue due to permanent cease of generation operations at Oyster Creek in Q3 2018, partially offset by • increased capacity prices
Midwest	$(89)	• the absence of the revenue recognized in the first quarter 2018 related to ZECs generated in Illinois from June through December 2017, partially offset by • increased capacity prices and • higher realized energy prices
New York	$(18)	• lower realized energy prices
ERCOT	$38	• higher realized energy prices
Other Power Regions	$(80)	• lower realized energy prices • decreased capacity prices
Proprietary Trading	$(2)	• congestion activity
Mark-to-market[(a)]	$238	• losses on economic hedging activities of $28 million in 2019 compared to losses of $266 million in 2018
Other	$(48)	• the impacts of declining natural gas prices
Total	$(128)	

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(a) See Note 10 — Derivative Financial Instruments for additional information on mark-to-market losses.

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

	Three Months Ended March 31,	
	2019	2018
Nuclear fleet capacity factor	97.1%	96.5%
Refueling outage days	74	68
Non-refueling outage days	—	6

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

	Three Months Ended March 31, 2019 Increase (Decrease)
Labor, other benefits, contracting, materials[a]	$ (34)
Nuclear refueling outage costs, including the co-owned Salem plants	6
Corporate allocations	(10)
Insurance[b]	30
Merger and integration costs	(4)
Plant retirements and divestitures[c]	(101)
Cost management program	7
Long-lived asset impairments	5
Pension and non-pension postretirement benefits expense	(16)
Allowance for uncollectible accounts	(11)
Other	7
Decrease in Operating and maintenance expense	$ (121)

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(a) Primarily reflects decreased costs related to the permanent cease of generation operations at Oyster Creek in the third quarter of 2018.
(b) Primarily reflects the absence of a supplemental NEIL insurance distribution received in the first quarter 2018.
(c) Primarily due to the benefit recorded in 2019 for the remeasurement of the TMI ARO and the increase to materials and supplies inventory reserves in 2018 associated with Generation’s decision to early retire the Oyster Creek nuclear facility.

Depreciation and Amortization Expense for the three months ended March 31, 2019 compared to the same period in 2018 decreased primarily due to the permanent cease of generation operations at Oyster Creek in the third quarter of 2018.

Gain on Sales of Assets and Businesses for the three months ended March 31, 2019 compared to the same period in 2018 decreased primarily due to Generation's sale of its electrical contracting business in the first quarter of 2018.

Other, net for the three months ended March 31, 2019 compared to the same period in 2018 increased primarily due to the change in the unrealized gains and losses related to NDT funds of Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $(85) million and $(7) million for the three months ended March 31, 2019 and 2018, respectively, related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units. See Note 13 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT funds.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units:

	Three Months Ended March 31, 2019	2018
Net unrealized gains (losses) on NDT funds	$ 280	$ (96)
	29	28

Net realized
gains on sale
of NDT funds

Effective income tax rates were 34.3% and 4.5% for the three months ended March 31, 2019 and 2018, respectively. The change is primarily related to an increase in qualified nuclear decommissioning trust fund income and a decrease in renewable tax credits. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

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ComEd

Results of Operations — ComEd

	Three Months Ended March 31, 2019	2018	Favorable (Unfavorable) Variance
Operating revenues	$1,408	$1,512	$ (104)
Purchased power expense	485	605	120
Revenues net of purchased power expense	923	907	16
Other operating expenses			
Operating and maintenance	321	313	(8)
Depreciation and amortization	251	228	(23)
Taxes other than income	78	77	(1)
Total other operating expenses	650	618	(32)
Gain on sales of assets	3	3	—
Operating income	276	292	(16)
Other income and (deductions)			
Interest expense, net	(87)	(89)	2
Other, net	8	8	—
Total other income and (deductions)	(79)	(81)	2
Income before income taxes	197	211	(14)
Income taxes	40	46	6
Net income	$157	$165	$ (8)

Three Months Ended March 31, 2019 Compared to Three Months Ended March 31, 2018. Net income remained relatively consistent for the three months ended March 31, 2019 as compared to the same period in 2018.

Revenues Net of Purchased Power Expense. There are certain drivers of Operating revenues that are fully offset by their impact on Purchased power expense, such as commodity, REC, and ZEC procurement costs and participation in customer choice programs. ComEd recovers electricity, REC, and ZEC procurement costs from customers without mark-up. Therefore, fluctuations in these costs have no impact on RNF.

Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries but do impact Operating revenues related to supplied electricity.

The changes in RNF consisted of the following:

	Three Months Ended March 31, 2019 Increase (Decrease)
Electric distribution	$ 25
Transmission	9
Energy efficiency	13
Uncollectible accounts recovery, net	—
Other	(31)
Total increase	$ 16

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

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ComEd

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, investments being recovered, and allowed ROE. Electric distribution revenue increased during the three months ended March 31, 2019 as compared to the same period in 2018, primarily due to the impact of higher rate base and increased operating and maintenance and depreciation expenses. See Operating and maintenance and Depreciation and amortization expense discussions below and Note 6 — Regulatory Matters.

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 March 31, 2019 as compared to the same period in 2018, primarily due to the increased peak load and higher rate base. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Energy Efficiency Revenue. FEJA provides for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Under FEJA, energy efficiency revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, and allowed ROE. Energy efficiency revenue increased during the three months ended March 31, 2019 as compared to the same period in 2018, primarily due to the impact of higher rate base. See Depreciation and amortization expense discussions below and Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Uncollectible Accounts Recovery, Net represents recoveries under the uncollectible accounts tariff. See Operating and maintenance expense discussion below for additional information on this tariff.

Other revenue, includes rental revenue, revenue related to late payment charges, mutual assistance revenues, and recoveries of environmental costs associated with MGP sites. The decrease in Other revenue three months ended March 31, 2019 as compared to the same period in 2018 primarily reflects absence of mutual assistance revenues associated with hurricane and winter storm restoration efforts that occurred in Q1 2018. An equal and offsetting amount was included in Operating and maintenance expense and Taxes other than income.

See Note 18 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ComEd's revenue disaggregation.

The increase in Operating and maintenance expense consisted of the following:

	Three Months Ended March 31, 2019 Increase (Decrease)
Baseline	
Labor, other benefits, contracting and materials[a]	$ (6)
Pension and non-pension postretirement benefits expense[b]	(11)
Storm-related costs	18
BSC costs[a]	2
Other[a]	5
Total increase	$ 8

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(a)

Reflects absence of mutual assistance expenses. An equal and offsetting decrease has been recognized in Operating revenues for the period presented.

(b) Primarily reflects an increase in discount rates and the favorable impacts of the merger of two of Exelon's pension plans effective in January 2019, partially offset by lower than expected asset returns in 2018.

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ComEd

The increase in Depreciation and amortization expense consisted of the following:

	Three Months Ended March 31, 2019 Increase (Decrease)
Depreciation and amortization[(a)]	$ 18
Regulatory asset amortization[(b)]	5
Total increase	$ 23

(a) Reflects ongoing capital expenditures and higher depreciation rates effective January 2019.
(b) Includes amortization of ComEd's energy efficiency formula rate regulatory asset.

Effective income tax rate was 20.3% and 21.8% for the three months ended March 31, 2019 and 2018, respectively. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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PECO

Results of Operations — PECO

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2019	2018	
Operating revenues	$900	$866	$ 34
Purchased power and fuel expense	331	333	2
Revenues net of purchased power and fuel expense	569	533	36
Other operating expenses			
Operating and maintenance	225	275	50
Depreciation and amortization	81	75	(6)
Taxes other than income	41	41	—
Total other operating expenses	347	391	44
Operating income	222	142	80
Other income and (deductions)			
Interest expense, net	(33)	(33)	—
Other, net	4	2	2
Total other income and (deductions)	(29)	(31)	2
Income before income taxes	193	111	82
Income taxes	25	(2)	(27)
Net income	$168	$113	$ 55

Three Months Ended March 31, 2019 Compared to Three Months Ended March 31, 2018. Net income increased by $55 million primarily due to lower storm costs, higher electric distribution rates as a result of the 2018 electric rate case settlement and higher gas distribution rates.

Revenues Net of Purchased Power and Fuel Expense

There are certain drivers of Operating revenues that are fully offset by their impact on Purchased power and fuel expense such as commodity and REC procurement costs and participation in customer choice programs. PECO recovers electricity, natural gas and REC procurement costs from customers without mark-up. Therefore, fluctuations in these costs have no impact on RNF.

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 or RNF, but impact Operating revenues related to supplied electricity and natural gas.

The changes in RNF consisted of the following:

	Three Months Ended March 31, 2019 Increase (Decrease)		
	Electric	Gas	Total
Weather	$—	$2	$2
Volume	1	1	2
Pricing	14	10	24
Regulatory required programs	10	4	14
Other	(7)	1	(6)
Total increase	$18	$18	$36

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PECO

Weather. The demand for electricity and natural gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as “favorable weather conditions” because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the three months ended March 31, 2019 compared to the same period in 2018, RNF increased slightly due to favorable weather conditions.

Heating and cooling degree-days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree-days for a 30-year period in PECO's service territory. The changes in heating and cooling degree-days in PECO’s service territory for the three months ended March 31, 2019 compared to the same period in 2018 and normal weather consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended March 31,	2019	2018	Normal	From 2018	2019 vs. Normal
Heating Degree-Days	2,432	2,397	2,429	1.5 %	0.1 %
Cooling Degree-Days	2	—	1	200.0%	100.0%

Volume. Electric volume, exclusive of the effects of weather, for the three months ended March 31, 2019 compared to the same period in 2018, increased due to a shift in the volume profile across classes from the commercial and industrial classes to the residential class. Natural gas volume for the three months ended March 31, 2019, compared to the same period in 2018, increased due to strong customer growth and moderate economic growth.

Electric Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31, 2019	2018	% Change	Weather - Normal % Change[(b)]
Residential	3,641	3,628	0.4 %	0.4 %
Small commercial & industrial	2,066	2,029	1.8 %	1.8 %
Large commercial & industrial	3,571	3,703	(3.6)%	(3.6)%
Public authorities & electric railroads	195	197	(1.0)%	(0.9)%
Total electric retail deliveries[(a)]	9,473	9,557	(0.9)%	(0.9)%

	As of March 31,	
Number of Electric Customers	2019	2018
Residential	1,485,698	1,474,555
Small commercial & industrial	153,042	151,947
Large commercial & industrial	3,107	3,113
Public authorities & electric railroads	9,638	9,541
Total	1,651,485	1,639,156

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

Natural Gas Deliveries to Customers (in mmcf)	Three Months Ended March 31, 2019	2018	% Change	Weather - Normal % Change[(b)]
Residential	21,218	20,574	3.1 %	1.2 %
Small commercial & industrial	10,644	10,417	2.2 %	0.1 %

Large commercial & industrial	19	47	(59.6)%	(10.8)%
Transportation	7,973	7,568	5.4 %	5.6 %
Total natural gas retail deliveries[(a)]	39,854	38,606	3.2 %	1.7 %

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PECO

	As of March 31,	
Number of Natural Gas Customers	2019	2018
Residential	483,560	478,565
Small commercial & industrial	44,274	44,053
Large commercial & industrial	1	4
Transportation	744	768
Total	528,579	523,390

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(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.
(a) Reflects the change in delivery volumes assuming normalized weather based on the historical 30-year average.

Pricing for the three months ended March 31, 2019 compared to the same period in 2018 increased primarily due to an increase in electric distribution rates charged to customers. The increase in electric distribution rates was effective January 1, 2019 in accordance with the 2018 PAPUC approved electric distribution rate case settlement. Additionally, the increase represents revenue from higher gas distribution rates. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs represents revenues collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency 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 Operating and maintenance expense, Depreciation and amortization expense and Income taxes.

Other revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues and wholesale transmission revenue.

See Note 18— Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of PECO's revenue disaggregation.

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

	Three Months Ended March 31, 2019 Increase (Decrease)
Baseline	
Labor, other benefits, contracting and materials	$ 7
Storm-related costs[a]	(56)
Pension and non-pension postretirement benefits expense	(2)
BSC costs	3
Other	(1)
	(49)
Regulatory Required Programs	
Energy efficiency	(1)
Total decrease	$ (50)

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(a) Reflects decreased storm costs due to the March 2018 winter storms.

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PECO

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

	Three Months Ended March 31, 2019 Increase (Decrease)
Depreciation and amortization[a]	$ 5
Regulatory asset amortization	1
Total increase	$ 6

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

Effective Income Tax Rates were 13.0% and (1.8)% for the three months ended March 31, 2019 and 2018, respectively. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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BGE

Results of Operations — BGE

	Three Months Ended March 31, 2019	2018	Favorable (Unfavorable) Variance
Operating revenues	$976	$977	$ (1)
Purchased power and fuel expense	360	380	20
Revenues net of purchased power and fuel expense	616	597	19
Other operating expenses			
Operating and maintenance	192	221	29
Depreciation and amortization	136	134	(2)
Taxes other than income	68	65	(3)
Total other operating expenses	396	420	24
Operating income	220	177	43
Other income and (deductions)			
Interest expense, net	(29)	(25)	(4)
Other, net	5	4	1
Total other income and (deductions)	(24)	(21)	(3)
Income before income taxes	196	156	40
Income taxes	36	28	(8)
Net income	$160	$128	$ 32

Three Months Ended March 31, 2019 Compared to Three Months Ended March 31, 2018. Net income increased by $32 million primarily due to higher gas distribution rates and lower storm costs, partially offset by higher interest expense due to the September 2018 debt issuance.

Revenues Net of Purchased Power and Fuel Expense. There are certain drivers to Operating revenues that are fully offset by their impact on Purchased power and fuel expense, such as commodity procurement costs and participation in customer choice programs. BGE recovers electricity, natural gas and procurement costs from customers without mark-up. Therefore, fluctuations in these costs have no impact on RNF.

Customers have the choice to purchase electricity and natural gas from electric generation and natural gas competitive suppliers. Customer choice programs do not impact the volume of deliveries or RNF but impact Operating revenues related to supplied electricity and natural gas.

The changes in RNF consisted of the following:

	Three Months Ended March 31, 2019 Increase (Decrease) Electric	Gas	Total
Distribution	$4	$31	$35
Regulatory required programs	(2)	(3)	(5)
Transmission	(6)	—	(6)
Other, net	(4)	(1)	(5)
Total increase (decrease)	$(8)	$27	$19

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.

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BGE

Number of Electric Customers	As of March 31, 2019	2018
Residential	1,171,027	1,163,887
Small commercial & industrial	113,976	113,675
Large commercial & industrial	12,278	12,148
Public authorities & electric railroads	266	270
Total	1,297,547	1,289,980

Number of Gas Customers	As of March 31, 2019	2018
Residential	635,241	631,594
Small commercial & industrial	38,322	38,443
Large commercial & industrial	5,981	5,874
Total	679,544	675,911

Distribution Revenue increased for the three months ended March 31, 2019, compared to the same period in 2018, primarily due to the impact of higher gas distribution rates that became effective in January 2019. See Note 6 — 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 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 Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income.
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 March 31, 2019, compared to the same period in 2018. See Operating and Maintenance Expense below and Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.
Other revenue includes revenue related to service application fees, mutual assistance revenues, late payment charges, and off-system sales.
See Note 18 — Segment Information of the Combined Notes to the Consolidated Financial Statements for the presentation of BGE's revenue disaggregation.

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BGE

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

	Three Months Ended March 31, 2019 Increase (Decrease)
Baseline	
Storm-related costs[(a)]	$ (28)
BSC costs	2
Other	(2)
	(28)
Regulatory Required Programs	
Other	(1)
Total decrease	$ (29)

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(a) Reflects decreased storm costs due to the March 2018 winter storms.

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

	Three Months Ended March 31, 2019 Increase (Decrease)
Depreciation and amortization[(a)]	$ 5
Regulatory asset amortization	1
Regulatory required programs	(4)
Total increase	$ 2

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

Effective income tax rates were 18.4% and 17.9% for the three months ended March 31, 2019 and 2018, respectively. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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PHI

Results of Operations — PHI

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

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2019	2018	
PHI	$117	$65	$ 52
Pepco	55	31	24
DPL	53	31	22
ACE	10	7	3
Other[a]	(1)	(4)	3

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

Three Months Ended March 31, 2019 Compared to Three Months Ended March 31, 2018. Net Income increased by $52 million primarily due to higher distribution and transmission base rates, lower uncollectible accounts expense, lower storm costs, and the absence of a write-off of construction work in progress.

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Pepco

Results of Operations — Pepco

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2019	2018	
Operating revenues	$575	$557	$ 18
Purchased power expense	187	182	(5)
Revenues net of purchased power expense	388	375	13
Other operating expenses			
Operating and maintenance	118	130	12
Depreciation and amortization	94	96	2
Taxes other than income	92	93	1
Total other operating expenses	304	319	15
Operating income	84	56	28
Other income and (deductions)			
Interest expense, net	(34)	(31)	(3)
Other, net	7	8	(1)
Total other income and (deductions)	(27)	(23)	(4)
Income before income taxes	57	33	24
Income taxes	2	2	—
Net income	$55	$31	$ 24

Three Months Ended March 31, 2019 Compared to Three Months Ended March 31, 2018. Net income increased by $24 million primarily due to higher electric distribution base rates in Maryland that became effective June 2018, higher electric distribution base rates in the District of Columbia that became effective August 2018, an increase in the Network Transmission Service rate that became effective June 2018, an increase in the highest daily peak load, and lower storm costs.

Revenues Net of Purchased Power Expense. There are certain drivers of Operating revenues that are fully offset by their impact on Purchased power expense, such as commodity and REC procurement costs and participation in customer choice programs. Pepco recovers electricity and REC procurement costs from customers with a slight mark-up. Therefore, fluctuations in these costs have minimal impact on RNF.

Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries or RNF, but impact Operating revenues related to supplied electricity.

The changes in RNF consisted of the following:

	Three Months Ended March 31, 2019 Increase (Decrease)
Volume	$ 4
Distribution	6
Regulatory required programs	(10)
Transmission	13

Total increase	$ 13

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

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Pepco

charge per customer by customer class. While Operating revenues are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers.
Volume, exclusive of the effects of weather, increased for the three months ended March 31, 2019 compared to the same period in 2018, primarily due to the impact of residential customer growth.

	As of March 31,	
Number of Electric Customers	2019	2018
Residential	809,845	797,105
Small commercial & industrial	54,295	53,602
Large commercial & industrial	22,030	21,718
Public authorities & electric railroads	153	146
Total	886,323	872,571

Distribution Revenues increased for the three months ended March 31, 2019 compared to the same period in 2018 primarily due to higher electric distribution base rates charged to customers in Maryland that became effective in June 2018 and higher electric distribution base rates charged to customers in the District of Columbia that became effective in August 2018. See Note 6 - 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, DC PLUG and SOS 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 Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income.
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 increased for the three months ended March 31, 2019 compared to the same period in 2018 primarily due to an increase in the Network Transmission Service rate that became effective June 2018 and an increase in the highest daily peak load.
Other revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues and recoveries of other taxes.
See Note 18 - Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of Pepco's revenue disaggregation.

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Pepco

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

	Three Months Ended March 31, 2019 Increase (Decrease)
Baseline	
Labor, other benefits, contracting and materials	$ (5)
Pension and non-pension postretirement benefits expense	1
Uncollectible accounts expense	(2)
Storm-related costs	(3)
BSC and PHISCO costs	(3)
Other	(1)
	(13)
Regulatory required programs	1
Total decrease	$ (12)

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

	Three Months Ended March 31, 2019 Increase (Decrease)
Depreciation and amortization[(a)]	$ 5
Regulatory required programs[(b)]	(7)
Total decrease	$ (2)

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

(b) Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

Effective income tax rates were 3.5% and 6.1% for the three months ended March 31, 2019 and 2018, respectively. The decrease is primarily due to the accelerated amortization of certain deferred income tax regulatory liabilities established upon the enactment of TCJA as the result of regulatory settlements. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates.

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DPL

Results of Operations — DPL

	Three Months Ended March 31, 2019	2018	Favorable (Unfavorable) Variance
Operating revenues	$380	$384	$ (4)
Purchased power and fuel expense	164	177	13
Revenues net of purchased power and fuel expense	216	207	9
Other operating expenses			
Operating and maintenance	84	98	14
Depreciation and amortization	46	45	(1)
Taxes other than income	14	15	1
Total other operating expenses	144	158	14
Operating income	72	49	23
Other income and (deductions)			
Interest expense, net	(15)	(13)	(2)
Other, net	3	2	1
Total other income and (deductions)	(12)	(11)	(1)
Income before income taxes	60	38	22
Income taxes	7	7	—
Net income	$53	$31	$ 22

Three Months Ended March 31, 2019 Compared to Three Months Ended March 31, 2018. Net income increased by $22 million primarily due to higher electric distribution base rates charged to customers in Maryland and Delaware that were put into effect throughout 2018, higher transmission base rates and an increase in the highest daily peak load, the absence of a write-off of construction work in progress, lower uncollectible accounts expense, and lower storm costs.

Revenues Net of Purchased Power and Fuel Expense. There are certain drivers to Operating revenues that are fully offset by their impact on Purchased power and fuel expense, such as commodity and REC procurement costs and participation in customer choice programs. DPL recovers electricity and REC procurement costs from customers with a slight mark-up and natural gas costs from customers without mark-up. Therefore, fluctuations in these costs have minimal impact on RNF.

Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries or RNF, but impact Operating revenues related to supplied electricity.

The changes in RNF consisted of the following:

	Three Months Ended March 31, 2019 Increase (Decrease) Electric	Gas	Total
Volume	$—	$1	$ 1
Distribution	4	(2)	2
Regulatory required programs	(2)	—	(2)
Transmission	8	—	8

Total increase (decrease)	$10	$(1)	$ 9

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

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DPL

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. There was no change in RNF related to weather for the three months ended March 31, 2019 compared to same period in 2018.

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. There were no cooling degree days in DPL's Delaware electric service territory for the three months ended March 31, 2019 or during the same period in 2018. The changes in heating degree days in DPL's Delaware service territory for the three months ended March 31, 2019 compared to same period in 2018 and normal weather consisted of the following:

Delaware Electric Service Territory				% Change	
Three Months Ended March 31,	2019	2018	Normal	2019 vs. 2018	2019 vs. Normal
Heating Degree-Days	2,522	2,504	2,508	0.7%	0.6 %

Delaware Natural Gas Service Territory				% Change	
Three Months Ended March 31,	2019	2018	Normal	2019 vs. 2018	2019 vs. Normal
Heating Degree-Days	2,522	2,504	2,496	0.7%	1.0 %

Volume, exclusive of the effects of weather, remained relatively consistent for the three months ended March 31, 2019 compared to the same period in 2018.

Electric Retail Deliveries to Delaware Customers (in GWhs)	Three Months Ended March 31, 2019	2018	% Change	Weather - Normal % Change[(b)]
Residential	851	869	(2.1)%	(1.5)%
Small commercial & industrial	321	330	(2.7)%	(2.6)%
Large commercial & industrial	810	829	(2.3)%	(2.2)%
Public authorities & electric railroads	8	9	(11.1)%	(7.3)%
Total electric retail deliveries[(a)]	1,990	2,037	(2.3)%	(2.0)%

Number of Total Electric Customers (Maryland and Delaware)	As of March 31, 2019	2018
Residential	464,638	460,863
Small commercial & industrial	61,391	60,962
Large commercial & industrial	1,400	1,383
Public authorities & electric railroads	620	625
Total	528,049	523,833

(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.

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DPL

Natural Gas Retail Deliveries to Delaware Customers (in mmcf)	Three Months Ended March 31, 2019	2018	% Change	Weather - Normal % Change[b]
Residential	4,607	4,485	2.7 %	1.8 %
Small commercial & industrial	2,020	1,878	7.6 %	6.6 %
Large commercial & industrial	523	516	1.4 %	1.4 %
Transportation	2,218	2,213	0.2 %	(0.2)%
Total natural gas deliveries[a]	9,368	9,092	3.0 %	2.3 %

Number of Delaware Gas Customers	As of March 31, 2019	2018
Residential	124,575	123,062
Small commercial & industrial	10,023	9,873
Large commercial & industrial	18	17
Transportation	157	155
Total	134,773	133,107

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

Distribution Revenue increased for the three months ended March 31, 2019 compared to the same period in 2018 primarily due to higher electric distribution base rates and higher gas distribution interim base rates charged to customers in Maryland and Delaware that were put into effect throughout 2018. See Note 6 — 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, DE Renewable Portfolio Standards, SOS 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 Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income.

Transmission Revenues. Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered and the highest daily peak load, which is updated annually in January based on the prior calendar years. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. Transmission revenue increased for the three months ended March 31, 2019 compared to the same period in 2018 primarily due to higher rates effective June 2018 and an increase in the highest daily peak load.

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

See Note 18 - Segment Information for the Combined Notes to Consolidated Financial Statements for the presentation of DPL's revenue disaggregation.

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DPL

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

	Three Months Ended March 31, 2019 Increase (Decrease)
Baseline	
Labor, other benefits, contracting and materials	$ 3
Uncollectible accounts expense	(5)
Storm-related costs	(5)
BSC and PHISCO costs	(2)
Write-off of construction work in progress	(7)
Other	(1)
	(17)
Regulatory required programs	3
Total decrease	$ (14)

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

	Three Months Ended March 31, 2019 Increase (Decrease)
Depreciation and amortization[(a)]	$ 4
Regulatory required programs[(b)]	(3)
Total increase	$ 1

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

(b) Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

Effective income tax rates for the three months ended March 31, 2019 and 2018 were 11.7% and 18.4%, respectively. The decrease is primarily due to the accelerated amortization of certain deferred income tax regulatory liabilities established upon the enactment of TCJA as the result of regulatory settlements.

See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates.

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ACE

Results of Operations — ACE

	Three Months Ended March 31, 2019	2018	Favorable (Unfavorable) Variance
Operating revenues	$273	$310	$ (37)
Purchased power expense	139	161	22
Revenues net of purchased power expense	134	149	(15)
Other operating expenses			
Operating and maintenance	81	90	9
Depreciation and amortization	31	33	2
Taxes other than income	1	3	2
Total other operating expenses	113	126	13
Operating income	21	23	(2)
Other income and (deductions)			
Interest expense, net	(14)	(16)	2
Other, net	3	1	2
Total other income and (deductions)	(11)	(15)	4
Income before income taxes	10	8	2
Income taxes	—	1	1
Net income	$10	$7	$ 3

Three Months Ended March 31, 2019 Compared to Three Months Ended March 31, 2018. Net income increased by $3 million primarily due to increased transmission base rates that became effective June 2018 and an increase in the highest daily peak loads, partially offset by lower average residential usage.

Revenues Net of Purchased Power and Fuel Expense. There are certain drivers to Operating revenues that are fully offset by their impact on Purchased power and fuel expense, such as commodity and REC procurement costs and participation in customer choice programs. ACE recovers electricity and REC procurement costs from customers without mark-up. Therefore, fluctuations in these costs have no impact on RNF.

Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries or RNF, but impact Operating revenues related to supplied electricity.

The changes in RNF consisted of the following:

	Three Months Ended March 31, 2019 Increase (Decrease)
Volume	$ (6)
Distribution	(3)
Regulatory required programs	(11)
Transmission	5
Total decrease	$ (15)

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 no change in RNF related to weather for the three months ended March 31, 2019 compared to same period in 2018.

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ACE

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in ACE's service territory. There were no cooling degree days in ACE's service territory for the three months ended March 31, 2019 or during the same period in 2018. The changes in heating degree days in ACE's service territory for the three months ended March 31, 2019 compared to same period in 2018 consisted of the following:

Heating Degree-Days				% Change	
Three Months Ended March 31,	2019	2018	Normal	2019 vs. 2018	2019 vs. Normal
Heating Degree-Days	2,506	2,413	2,489	3.9%	0.7 %

Volume, exclusive of the effects of weather, decreased for the three months ended March 31, 2019 compared to the same period in 2018, primarily due to lower average residential usage.

Electric Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31, 2019	2018	% Change	Weather - Normal % Change[b]
Residential	908	990	(8.3)%	(8.8)%
Small commercial & industrial	310	314	(1.3)%	(1.3)%
Large commercial & industrial	791	824	(4.0)%	(4.1)%
Public authorities & electric railroads	13	15	(13.3)%	(10.6)%
Total electric retail deliveries[a]	2,022	2,143	(5.6)%	(5.9)%

	As of March 31,	
Number of Electric Customers	2019	2018
Residential	491,935	488,495
Small commercial & industrial	61,377	61,059
Large commercial & industrial	3,494	3,611
Public authorities & electric railroads	661	643
Total	557,467	553,808

(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 decreased for the three months ended March 31, 2019 compared to the same period in 2018 primarily due to the accelerated amortization of certain deferred income tax regulatory liabilities established upon the enactment of TCJA as the result of regulatory settlements. See Note 4 — 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 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 Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income.

Transmission Revenues. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered and the highest daily peak load, which is updated annually in January based on the prior calendar year. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. Transmission revenue increased for the three months ended

March 31, 2019 compared to the same period in 2018 primarily due to a rate increase effective June 2018 and an increase in the highest daily peak loads.

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ACE

Other revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues and recoveries of other taxes.
See Note 18 - Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ACE's revenue disaggregation.
The changes in Operating and maintenance expense consisted of the following:

	Three Months Ended March 31, 2019 Increase (Decrease)
Baseline	
Labor, other benefits, contracting and materials	$ (4)
Uncollectible accounts expense[(a)]	(5)
Storm-related costs	(2)
BSC and PHISCO costs	(2)
Other	(6)
	(19)
Regulatory required programs	10
Total decrease	$ (9)

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(a) ACE is allowed to recover from or refund to customers the difference between its annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. An equal and offsetting amount has been recognized in Operating revenues.

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

	Three Months Ended March 31, 2019 Increase (Decrease)
Depreciation and amortization[(a)]	$ 2
Regulatory required programs[(b)]	(4)
Total decrease	$ (2)

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(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.
(b) Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

Effective income tax rates were 0% and 12.5% for the three months ended March 31, 2019 and 2018, respectively. The decrease is primarily due to the accelerated amortization of certain deferred income tax regulatory liabilities established upon the enactment of TCJA as the result of regulatory settlements.

See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates.

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Liquidity and Capital Resources

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

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each 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 unsecured revolving credit facilities with aggregate bank commitments of $9 billion. In addition, Generation has $645 million in bilateral facilities with banks which have various expirations between October 2019 and April 2021 and $159 million in credit facilities for project finance. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the "Credit Matters" section below for additional information. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and 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, ComEd, PECO, BGE, Pepco, DPL and ACE 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 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' debt and credit agreements.

NRC Minimum Funding Requirements (Exelon and Generation)

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are 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 13 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional information.

If a nuclear plant were to early retire there is a risk that it will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT fund investments could appreciate in value. A shortfall could require that Generation address the shortfall by, among other things, obtaining a parental guarantee for Generation's share of the funding assurance. However, the amount of any guarantees or other assurance will ultimately depend on the decommissioning approach, the associated level of costs, and the NDT fund investment performance going forward. Within two years after shutting down a plant, Generation must submit a post-shutdown decommissioning activities report (PSDAR) to the NRC that includes the planned option for decommissioning the site. As of March 31, 2019, across the alternative decommissioning approaches available, Exelon would not be required to post a parental guarantee for TMI or Oyster Creek. See Note 13 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional information.

Upon issuance of any required financial guarantees, each site would be able to utilize the respective NDT funds for radiological decommissioning costs, which represent the majority of the total expected decommissioning costs. However, the NRC must approve an additional exemption in order for the plant's owner(s) to utilize the NDT fund to pay for non-radiological decommissioning costs (i.e., spent fuel management and site restoration costs). If a unit does not receive this exemption, the costs would be borne by the owner(s). While the ultimate amounts may vary greatly and could be reduced by alternate decommissioning scenarios and/or reimbursement of certain costs under the DOE reimbursement agreements or future litigation, across the alternative decommissioning approaches available, if TMI were to fail to obtain the exemption, Generation estimates it could incur spent fuel management and site restoration costs over the next ten years of up to $90 million net of taxes under SAFSTOR. On April 5, 2019, Generation filed with the NRC the TMI PSDAR which details the selection of the SAFSTOR option for

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decommissioning the plant. On October 19, 2018, the NRC granted Generation's exemption request to use the Oyster Creek NDT funds for non-radiological decommissioning costs.

On July 31, 2018, Generation entered into an agreement for the sale of Oyster Creek which is expected to occur in the second half of 2019. See Note 3 - Mergers, Acquisitions and Dispositions for additional information on the sale of Oyster Creek to Holtec.

Cash Flows from Operating Activities

General

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

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

See Notes 4 — Regulatory Matters and 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2018 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 provided by (used in) operating activities for the three months ended March 31, 2019 and 2018 by Registrant:

Change - Cash Provided by (Used in)	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net income	$330	$ 236	$ (8)	$ 55	$32	$52	$24	$22	$ 3
Add (subtract):									
Non-cash operating activities	(494)	(575)	17	10	15	(38)	(15)	(16)	(8)
Pension and non-pension postretirement benefit contributions	3	(16)	(29)	(1)	5	49	3	—	6
Income taxes	55	67	10	15	(6)	13	7	10	(1)
Changes in working capital and other noncurrent assets and liabilities	(498)	(145)	(23)	(21)	(113)	(126)	(64)	(33)	1
Option premiums received, net	33	33	—	—	—	—	—	—	—
Collateral posted, net	113	127	(10)	—	(1)	—	—	—	—
Net cash flows provided by (used in) operations	$(458)	$ (273)	$ (43)	$ 58	$(68)	$(50)	$(45)	$(17)	$ 1

Changes in the Registrants' cash flows from operations were generally consistent with changes in each Registrant’s respective results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. In addition, significant operating cash flow impacts for the Registrants for the three months ended March 31, 2019 and 2018 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.
- 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.

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Cash Flows from Investing Activities

The following table provides a summary of the change in cash provided by (used in) investing activities for the three months ended March 31, 2019 and 2018 by Registrant:

Change - Cash Provided by (Used in)	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Capital expenditures	$ 7	$ 117	$ 28	$ (5)	$ (34)	$ (100)	$ (17)	$ (13)	$ (65)
Proceeds from NDT fund sales, net	106	106	—	—	—	—	—	—	—
Proceeds from sales of assets and businesses	(71)	(71)	—	—	—	—	—	—	—
Other investing activities	29	30	3	—	—	1	1	—	1
Net cash flows provided by (used in) investing activities	$ 71	$ 182	$ 31	$ (5)	$ (34)	$ (99)	$ (16)	$ (13)	$ (64)

Significant investing cash flow impacts for the Registrants for three months ended March 31, 2019 and 2018 were as follows:

- Variances in capital expenditures are primarily due to the timing of cash expenditures for capital projects. Refer to Liquidity and Capital Resources of the Exelon 2018 Form 10-K for additional information on projected capital expenditure spending.
- During the three months ended March 31, 2018, Exelon and Generation had proceeds of $79 million relating to the sale of its interest in an electrical contracting business.

Capital Expenditure Spending

As of March 31, 2019, there have been no material changes to the Registrants' projected capital expenditures as disclosed in Liquidity and Capital Resources of the Exelon 2018 Form 10-K.

Cash Flows from Financing Activities

The following table provides a summary of the change in cash provided by (used in) financing activities for the three months ended March 31, 2019 and 2018 by Registrant:

Change - Cash Provided by (Used in)	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Changes in short-term borrowings, net	$ (186)	$ (165)	$ 5	$ (220)	$ 103	$ 90	$ 31	$ 10	$ 49
Long-term debt, net	161	(20)	—	175	—	7	—	4	4
Changes in Exelon intercompany money pool	—	(100)	—	(194)	—	(13)	—	—	—
Dividends paid on common stock	(19)	—	(13)	197	(4)	—	1	(5)	(3)
Distributions to member	—	(37)	—	—	—	(57)	—	—	—
Contributions from parent/member	—	—	(50)	145	—	19	14	—	5
Other financing activities	55	3	—	5	—	—	—	—	—
Net cash flows provided by (used in) financing activities	$ 11	$ (319)	$ (58)	$ 108	$ 99	$ 46	$ 46	$ 9	$ 55

Significant financing cash flow impacts for the Registrants for the three months ended March 31, 2019 and 2018 were as follows:

- Changes in short-term borrowings, net, is driven by repayments on and issuances of notes due in less than 90 days. Refer to 11 — 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 11 — Debt and Credit Agreements of the Consolidated Financial Statements for additional information on debt issuances. Refer to debt redemptions tables below for more information.

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- 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 16 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2018 Form 10-K for additional information on dividend restrictions. See below for quarterly dividends declared.

Debt

See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants’ debt issuances.

During the three months ended March 31, 2019, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Generation	Antelope Valley DOE Nonrecourse Debt	2.33% - 3.56%	January 5, 2037	$ 5
Generation	Kennett Square Capital Lease	7.83 %	September 20, 2020	$ 1
Generation	Continental Wind Nonrecourse Debt	6.00 %	February 28, 2033	$ 18
Generation	Pollution control notes	2.50 %	March 1, 2019	$ 23
ComEd	First Mortgage Bonds	2.15 %	January 15, 2019	$ 300
ACE	Transition Bonds	5.55 %	October 20, 2023	$ 4

Antelope Valley’s nonrecourse debt of $502 million was reclassified as current in Exelon’s and Generation’s Consolidated Balance Sheets as of March 31, 2019 as a result of the PG&E bankruptcy filing on January 29, 2019. See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

Dividends

Quarterly dividends declared by the Exelon Board of Directors during the three months ended March 31, 2019 and for the second quarter of 2019 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share[(a)]
First Quarter 2019	February 5, 2019	February 20, 2019	March 8, 2019	$0.3625
Second Quarter 2019	April 30, 2019	May 15, 2019	June 10, 2019	$0.3625

(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.

Other

For the three months ended March 31, 2019, other financing activities primarily consist of debt issuance costs. See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants’ debt issuances.

Credit Matters

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 $9.8 billion in aggregate total commitments of which no financial institution has more than 7% of the aggregate commitments for the Registrants. The Registrants had access to the commercial paper market during the first quarter of 2019 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of

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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 2018 Form 10-K for additional information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of March 31, 2019, it would have been required to provide incremental collateral of $1.9 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 $4.4 billion of available credit capacity of its revolver.

The following table presents the incremental collateral that each Utility Registrant would have been required to provide in the event each Utility Registrant lost its investment grade credit rating at March 31, 2019 and available credit facility capacity prior to any incremental collateral at March 31, 2019:

	PJM Credit Policy Collateral	Other Incremental Collateral Required[(a)]	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 8	$ —	$ 997
PECO	1	34	600
BGE	12	46	600
Pepco	11	—	292
DPL	5	14	300
ACE	—	—	300

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

Exelon Credit Facilities

Exelon Corporate, ComEd, BGE, Pepco, DPL and ACE 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 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 11 — Debt and Credit Agreements and Note 16 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' short-term borrowing activity.

See Note 13 — Debt and Credit Agreements and Note 22 — Commitments and Contingencies of the Exelon 2018 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

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

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, both Exelon and PHI operate an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of March 31, 2019, are presented in the following table:

Exelon Intercompany Money Pool	During the Three Months Ended March 31, 2019		As of March 31, 2019
Contributed (Borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Exelon Corporate	$ 467	$ —	$ 189
Generation	—	(235)	—
PECO	15	(10)	—
BSC	—	(383)	(248)
PHI Corporate	—	(9)	(1)
PCI	60	—	60

PHI Intercompany Money Pool	During the Three Months Ended March 31, 2019		As of March 31, 2019
Contributed (Borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
PHI Corporate	$ 9	$ —	$ —
PHISCO	4	(7)	2

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 2019. 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.

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Regulatory Authorizations

ComEd, PECO, BGE, Pepco, DPL and ACE are required to obtain short-term and long-term financing authority from Federal and State Commissions as follows:

	As of March 31, 2019					
	Short-term Financing Authority[a]			Remaining Long-term Financing Authority[a]		
	Commission	Expiration Date	Amount	Commission	Expiration Date	Amount
ComEd[b]	FERC	December 31, 2019	$ 2,500	ICC	2019 & 2021	$ 1,133
PECO[c]	FERC	December 31, 2019	1,500	PAPUC	December 31, 2021	1,900
BGE	FERC	December 31, 2019	700	MDPSC	N/A	400
Pepco	FERC	December 31, 2019	500	MDPSC / DCPSC	December 31, 2020	400
DPL	FERC	December 31, 2019	500	MDPSC / DPSC	December 31, 2020	150
ACE[d]	NJBPU	December 31, 2019	350	NJBPU	December 31, 2019	—

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

(b) ComEd had $440 million available in long-term debt refinancing authority and $693 million available in new money long-term debt financing authority from the ICC as of March 31, 2019 and has an expiration date of June 1, 2019 and August 1, 2021, respectively.

(c) On April 18, 2019, ACE received approval from the NJBPU for $350 million long-term financing authority, expiring on December 31, 2020.

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 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in the Exelon 2018 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 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 2018 Form 10-K.

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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 2018 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 2019 through 2021.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation’s owned and contracted generation positions which have not been hedged. Exelon's hedging program involves the hedging of commodity price risk for Exelon's expected generation, typically on a ratable basis over three-year periods. As of March 31, 2019, the percentage of expected generation hedged is 90%-93%, 64%-67% and 38%-41% for 2019, 2020 and 2021, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generation based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation’s sales to the ComEd, PECO and BGE to serve their retail load.

A portion of Generation’s hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation’s entire economic hedge portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on March 31, 2019 market conditions and hedged position would be a decrease in pre-tax net income of approximately $25 million, $279 million and $551 million, respectively, for 2019, 2020 and 2021. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation actively manages its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation’s portfolio. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Proprietary Trading Activities

Proprietary trading portfolio activity for the three months ended March 31, 2019 resulted in $4 million of pre-tax gains due to net mark-to-market gains of $2 million and realized gains of $2 million. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading

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portfolio in comparison to Generation's total Revenue net of purchased power and fuel expense. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Fuel Procurement

Generation procures natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 62% of Generation's uranium concentrate requirements from 2019 through 2023 are supplied by three producers. 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.

ComEd

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC's December 18, 2013 Order approved the reduction of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved by the ICC in March 2014.

ComEd has block energy contracts to procure electric supply that are executed through a competitive procurement process, which is further discussed in Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements. The block energy contracts are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. ComEd does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

PECO, BGE, Pepco, DPL and ACE

PECO, BGE, Pepco, DPL and ACE have contracts to procure electric supply that are executed through a competitive procurement process, which are further discussed in Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements. BGE, Pepco, DPL and ACE have certain full requirements contracts, which are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. Other full requirements contracts are not derivatives.

PECO, BGE and DPL have also executed derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge their long-term price risk in the natural gas market. The hedging programs for natural gas procurement have no direct impact on their financial statements.

PECO, BGE, Pepco, DPL and ACE do not execute derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities

The following table detailing Exelon's, Generation's and ComEd's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

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The following table provides detail on changes in Exelon's, Generation's and ComEd's commodity mark-to-market net asset or liability balance sheet position from December 31, 2018 to March 31, 2019. 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 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of March 31, 2019 and December 31, 2018.

	Exelon	Generation	ComEd
Total mark-to-market energy contract net assets (liabilities) at December 31, 2018[(a)]	$ 299	$ 548	$ (249)
Total change in fair value during 2018 of contracts recorded in results of operations	(87)	(87)	—
Reclassification to realized of contracts recorded in results of operations	69	69	—
Changes in fair value — recorded through regulatory assets and liabilities[(b)]	9	—	9
Changes in allocated collateral	135	135	—
Net option premium paid/(received)	(6)	(6)	—
Option premium amortization	(37)	(37)	—
Upfront payments and amortizations[(c)]	(45)	(45)	—
Total mark-to-market energy contract net assets (liabilities) at March 31, 2019[(a)]	$ 337	$ 577	$ (240)

(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 or liabilities. As of March 31, 2019, ComEd recorded a regulatory liability of $240 million related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. For the three months ended March 31, 2019, ComEd also recorded $9 million of decreases in fair value and an increase for realized losses due to settlements of $80 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 9 — 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.

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Exelon

	Maturities Within 2019	2020	2021	2022	2023	2024 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[(a)(b)]:							
Actively quoted prices (Level 1)	$(11)	$(22)	$(1)	$(5)	$14	$ —	$ (25)
Prices provided by external sources (Level 2)	67	15	22	(1)	—	—	103
Prices based on model or other valuation methods (Level 3)[(c)]	152	210	36	(39)	(17)	(83)	259
Total	$208	$203	$57	$(45)	$(3)	$ (83)	$ 337

(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 $492 million at March 31, 2019.

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

Generation

	Maturities Within 2019	2020	2021	2022	2023	2024 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[(a)(b)]:							
Actively quoted prices (Level 1)	$(11)	$(22)	$(1)	$(5)	$ 14	$ —	$ (25)
Prices provided by external sources (Level 2)	67	15	22	(1)	—	—	103
Prices based on model or other valuation methods (Level 3)	172	235	61	(14)	9	36	499
Total	$228	$228	$82	$(20)	$ 23	$ 36	$ 577

(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 $492 million at March 31, 2019.

ComEd

	Maturities Within 2019	2020	2021	2022	2023	2024 and Beyond	Total Fair Value
Commodity derivative contracts[(a)]:							
Prices based on model or other valuation methods (Level 3)	$(20)	$(25)	$(25)	$(25)	$(26)	$(119)	$ (240)

(a) Represents ComEd’s net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk, Collateral and Contingent-Related Features (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

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fair value of contracts at the reporting date. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for detailed discussion of credit risk, collateral and contingent related features.
Generation
The following tables provide information on Generation’s credit exposure for all derivative instruments, normal purchases and normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of March 31, 2019. 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. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of $36 million, $31 million, $27 million, $37 million, $5 million and $4 million as of March 31, 2019, respectively.

Rating as of March 31, 2019	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	$ 819	$ 11	$ 808	1	$ 135
Non-investment grade	86	39	47		
No external ratings					
Internally rated — investment grade	162	—	162		
Internally rated — non-investment grade	87	7	80		
Total	$ 1,154	$ 57	$ 1,097	1	$ 135

	Maturity of Credit Risk Exposure			
Rating as of March 31, 2019	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$760	$ 47	$ 12	$ 819
Non-investment grade	87	(1)	—	86
No external ratings				
Internally rated — investment grade	110	26	26	162
Internally rated — non-investment grade	76	5	6	87
Total	$1,033	$ 77	$ 44	$ 1,154

Net Credit Exposure by Type of Counterparty	As of March 31, 2019
Financial institutions	$ 13
Investor-owned utilities, marketers, power producers	762
Energy cooperatives and municipalities	287
Other	35
Total	$ 1,097

(a) As of March 31, 2019, credit collateral held from counterparties where Generation had credit exposure included $37 million of cash and $19 million of letters of credit.

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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 2018 Annual Report on Form 10-K.
See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding credit exposure to suppliers.
Collateral (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 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding collateral requirements. See Note 16 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the letters of credit supporting the cash collateral.
Generation transacts output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon’s and Generation’s financial statements. As market prices rise above or fall below contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. To post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See ITEM 2. Liquidity and Capital Resources — Credit Matters — Exelon Credit Facilities for additional information.
The Utility Registrants
As of March 31, 2019, ComEd held $11 million in collateral from suppliers in association with energy procurement contracts, $31 million in collateral from suppliers for REC and ZEC contract obligations and $19 million in collateral from suppliers for long-term renewable energy contracts. BGE is not required to post collateral under its electric supply contracts but was holding an immaterial amount of collateral under its electric supply procurement contracts. BGE was not required to post collateral under its natural gas procurement contracts but was holding an immaterial amount of collateral under its natural gas procurement contracts. Pepco and DPL were not required to post collateral under their energy and/or natural gas procurement contracts, but were holding an immaterial amount of collateral under their respective electric supply procurement contracts. PECO and ACE were not required to post collateral under their energy and/or natural gas procurement contracts.
See Note 6 — Regulatory Matters and Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.
RTOs and ISOs (All Registrants)
All Registrants participate in all, or some, of the established wholesale spot energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot energy markets that are administered by the RTOs or ISOs, as applicable. In areas where there is no spot energy market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot energy markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot energy market transactions be shared by the remaining participants.

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Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' financial statements.

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

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

Interest Rate and Foreign Exchange Risk (All Registrants)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize interest rate swaps to manage their interest rate exposure. At March 31, 2019, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $619 million of notional amounts of floating-to-fixed hedges outstanding. A hypothetical 50 basis point increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $1 million decrease in Exelon Consolidated pre-tax income for the three months ended March 31, 2019. 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 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning its nuclear plants. As of March 31, 2019, Generation's NDT funds are reflected at fair value in its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $587 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information of equity price risk as a result of the current capital and credit market conditions.

Item 4. Controls and Procedures

During the first quarter of 2019, each of Exelon's, Generation's, ComEd's, PECO's, BGE's, PHI's, Pepco's, DPL's and ACE's 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 all Registrants to ensure that (a) material information relating to that Registrant, including its consolidated subsidiaries, is accumulated and made known to Exelon's management, including its principal executive officer and principal financial officer, by other employees of that Registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of March 31, 2019, the principal executive officer and principal financial officer of each of Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE concluded that such Registrant's disclosure controls and procedures were effective to accomplish its objectives. All 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.

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Beginning January 1, 2019, the Registrants adopted the Leases standard. As a result of guidance implementation, the Registrants' Operating lease ROU assets are now included in Other deferred debits and other assets and operating lease liabilities are included in Other current liabilities and Other deferred credits and other liabilities in the Consolidated Balance Sheets. The Registrants performed implementation controls, including lease reviews, to adopt the new standard, and implemented certain changes to their ongoing lease processes and control activities, which included enhancements to lease review and valuation processes, new training, and gathering of information for disclosures.
With the exception of the above, there have been no changes in internal control over financial reporting that occurred during the first quarter of 2019 that have materially affected, or are reasonably likely to materially affect, any of Exelon's, Generation's, ComEd's, PECO's, BGE's, PHI's, Pepco's, DPL's and ACE's internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see (a) ITEM 3. LEGAL PROCEEDINGS of Exelon's 2018 Form 10-K and (b) Notes 6 — Regulatory Matters and 16 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report. Such descriptions are incorporated herein by these references.

Item 1A. Risk Factors

Risks Related to Exelon

At March 31, 2019, the Registrants' risk factors were consistent with the risk factors described in the Registrants' combined 2018 Form 10-K in ITEM 1A. RISK FACTORS.

Item 4. Mine Safety Disclosures

All Registrants

Not applicable to the Registrants.

Item 5. Other Information

Amendments to BGE, PECO and PHI Governing Documents

On May 1, 2019, BGE and PECO each adopted Amended and Restated Bylaws, and PHI entered into an Amended and Restated Limited Liability Company Agreement. The amendments are primarily intended to align certain administrative provisions, subject to differences required by each Company's jurisdiction of incorporation or formation. The sole material change effected by BGE's Amended and Restated Bylaws and PHI's Amended and Restated Limited Liability Company Agreement is the implementation of a provision whereby effective following the annual election of Directors in 2020, each independent director of the respective company must retire from the Board of Directors at or before the next annual meeting of shareholders following the director's 75th birthday. The provision further provides that the Board of Directors has full discretion to decline a tendered resignation if it determines, based on the recommendation of the Corporate Governance Committee of the Exelon Board of Directors, that it is in the best interests of the Company and its shareholders to extend the director's continued service for an additional period of time. In addition to the implementation of the same provision, PECO's Amended and Restated Bylaws also implements a provision declassifying the PECO Board of Directors effective from and after the annual election of directors in 2019, provided that any PECO director who was elected prior to the 2019 annual meeting of shareholders for a term that extends until after the 2019 annual meeting of shareholders shall not be required to stand for election, and shall continue as a director until the annual meeting at which the director's term expires or until his or her earlier death, resignation or removal.

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This summary is qualified by reference to the complete text of the BGE and PECO Amended and Restated Bylaws, and the PHI Amended and Restated Limited Liability Company Agreement, attached as Exhibits 3.1, 3.2 and 3.3, respectively, to this Report.

Appointment of New ComEd Director

On April 26, 2019, the Board of Directors of ComEd appointed Mr. Juan Ochoa to the Board to fill a vacancy created by an expansion of the size of the Board. Mr. Ochoa is not being appointed to any committees and will receive the standard compensation paid by ComEd to its outside directors, as disclosed in ComEd's most recent Information Statement in Schedule 14C.

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
3.1	Amended and Restated Bylaws of Baltimore Gas and Electric Company
3.2	Amended and Restated Bylaws of PECO Energy Company
3.3	Amended and Restated Limited Liability Company Agreement of Pepco Holdings LLC
4.1	Supplemental Indenture dated as of February 7, 2019 from Commonwealth Edison Company to BNY Mellon Trust Company of Illinois, as trustee, and D. G. Donovan, as co-trustee (File No. 001-01839, Form 8-K dated February 19, 2019, Exhibit 4.1)
4.2	One Hundred and Twenty-Second Supplemental Indenture, dated April 3, 2019, between Delmarva Power & Light Company and The Bank of New York Mellon, as trustee
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation
101.DEF	XBRL Taxonomy Extension Definition
101.LAB	XBRL Taxonomy Extension Labels
101.PRE	XBRL Taxonomy Extension Presentation

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Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2019 filed by the following officers for the following companies:

31-1 — Filed by Christopher M. Crane for Exelon Corporation

31-2 — Filed by Joseph Nigro for Exelon Corporation

31-3 — Filed by Kenneth W. Cornew for Exelon Generation Company, LLC

31-4 — Filed by Bryan P. Wright for Exelon Generation Company, LLC

31-5 — Filed by Joseph Dominguez for Commonwealth Edison Company

31-6 — Filed by Jeanne M. Jones for Commonwealth Edison Company

31-7 — Filed by Michael A. Innocenzo for PECO Energy Company

31-8 — Filed by Robert J. Stefani for PECO Energy Company

31-9 — Filed by Calvin G. Butler, Jr. 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

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Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes — Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2019 filed by the following officers for the following companies:

32-1 — Filed by Christopher M. Crane for Exelon Corporation

32-2 — Filed by Joseph Nigro for Exelon Corporation

32-3 — Filed by Kenneth W. Cornew for Exelon Generation Company, LLC

32-4 — Filed by Bryan P. Wright for Exelon Generation Company, LLC

32-5 — Filed by Joseph Dominguez for Commonwealth Edison Company

32-6 — Filed by Jeanne M. Jones for Commonwealth Edison Company

32-7 — Filed by Michael A. Innocenzo for PECO Energy Company

32-8 — Filed by Robert J. Stefani for PECO Energy Company

32-9 — Filed by Calvin G. Butler, Jr. 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

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SIGNATURES

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.
EXELON CORPORATION

/s/ CHRISTOPHER M. CRANE
Christopher M. Crane

President and Chief Executive Officer
(Principal Executive Officer) and Director

/s/ JOSEPH NIGRO
Joseph Nigro
Senior Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ FABIAN E. SOUZA
Fabian E. Souza
Senior Vice President and Corporate Controller
(Principal Accounting Officer)
May 2, 2019

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Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.
EXELON GENERATION COMPANY, LLC

/s/ KENNETH W. CORNEW	/s/ BRYAN P. WRIGHT
Kenneth W. Cornew	Bryan P. Wright
President and Chief Executive Officer	Senior Vice President and Chief Financial Officer
(Principal Executive Officer)	(Principal Financial Officer)

/s/ MATTHEW N. BAUER
Matthew N. Bauer
Vice President and Controller
(Principal Accounting Officer)
May 2, 2019

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Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.
COMMONWEALTH EDISON COMPANY

/s/ JOSEPH DOMINGUEZ
Joseph Dominguez

Chief Executive Officer
(Principal Executive Officer)

/s/ JEANNE M. JONES
Jeanne M. Jones
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

/s/ GERALD J. KOZEL
Gerald J. Kozel
Vice President and Controller
(Principal Accounting Officer)
May 2, 2019

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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	Robert J. Stefani
President and Chief Executive Officer	Senior Vice President, Chief Financial Officer and Treasurer
(Principal Executive Officer)	(Principal Financial Officer)

/s/ SCOTT A. BAILEY
Scott A. Bailey
Vice President and Controller
(Principal Accounting Officer)
May 2, 2019

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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/ CALVIN G. BUTLER, JR.	/s/ DAVID M. VAHOS
Calvin G. Butler, Jr.	David M. Vahos
Chief Executive Officer (Principal Executive Officer)	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)

/s/ ANDREW W. HOLMES
Andrew W. Holmes
Vice President and Controller
(Principal Accounting Officer)
May 2, 2019

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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	Phillip S. Barnett
President and Chief Executive Officer	Senior Vice President, Chief Financial Officer and Treasurer
(Principal Executive Officer)	(Principal Financial Officer)

/s/ ROBERT M. AIKEN
Robert M. Aiken
Vice President and Controller
(Principal Accounting Officer)
May 2, 2019

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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	Phillip S. Barnett
President and Chief Executive Officer	Senior Vice President, Chief Financial Officer and Treasurer
(Principal Executive Officer)	(Principal Financial Officer)

/s/ ROBERT M. AIKEN
Robert M. Aiken
Vice President and Controller
(Principal Accounting Officer)
May 2, 2019

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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	Phillip S. Barnett
President and Chief Executive Officer	Senior Vice President, Chief Financial Officer and Treasurer
(Principal Executive Officer)	(Principal Financial Officer)

/s/ ROBERT M. AIKEN
Robert M. Aiken
Vice President and Controller
(Principal Accounting Officer)
May 2, 2019

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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	Phillip S. Barnett
President and Chief Executive Officer	Senior Vice President, Chief Financial Officer and Treasurer
(Principal Executive Officer)	(Principal Financial Officer)

/s/ ROBERT M. AIKEN
Robert M. Aiken
Vice President and Controller
(Principal Accounting Officer)
May 2, 2019