UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the Quarterly Period Ended June 30, 2017

or

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

Commission File Number	Name of Registrant; State or Other Jurisdiction of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
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) 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	52-2297449
001-01072	POTOMAC ELECTRIC POWER COMPANY (a District of Columbia and Virginia corporation) 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	53-0127880
001-01405	DELMARVA POWER & LIGHT COMPANY (a Delaware and Virginia corporation) 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	51-0084283
001-03559	ATLANTIC CITY ELECTRIC COMPANY (a New Jersey corporation) 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	21-0398280

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

Indicate by check mark whether the registrant has submitted electronically 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 ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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	☒				
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			☒		

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

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

The number of shares outstanding of each registrant’s common stock as of June 30, 2017 was:

Exelon Corporation Common Stock, without par value	960,087,898
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,017,160
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, $.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
Pepco Energy Services or PES	Pepco Energy Services, Inc. and its subsidiaries
PCI	Potomac Capital Investment Corporation and its subsidiaries
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
ACE Funding or ATF	Atlantic City Electric Transition Funding LLC
BSC	Exelon Business Services Company, LLC
PHISCO	PHI Service Company
Exelon Corporate	Exelon in its corporate capacity as a holding company
PHI Corporate	PHI in its corporate capacity as a holding company
Registrants	Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, collectively
Utility Registrants	ComEd, PECO, BGE, Pepco, DPL and ACE, collectively
AmerGen	AmerGen Energy Company, LLC
Antelope Valley	Antelope Valley Solar Ranch One
BondCo	RSB BondCo LLC
CENG	Constellation Energy Nuclear Group, LLC
ConEdison Solutions	The competitive retail electricity and natural gas business of Consolidated Edison Solutions, Inc., a subsidiary of Consolidated Edison, Inc.
Constellation	Constellation Energy Group, Inc.
EGTP	ExGen Texas Power, LLC
EGR	ExGen Renewables I, LLC
Entergy	Entergy Nuclear FitzPatrick, LLC
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
FitzPatrick	James A. FitzPatrick nuclear generating station
Legacy PHI	PHI, Pepco, DPL and ACE, collectively
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
PETT	PECO Energy Transition Trust
RPG	Renewable Power Generation
SolGen	SolGen, LLC
TMI	Three Mile Island nuclear facility
UII	Unicom Investments, Inc.
Ventures	Exelon Ventures Company, LLC

Other Terms and Abbreviations	
Note "—" of the Exelon 2016 Form 10-K	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2016 Annual Report on Form 10-K
Act 11	Pennsylvania Act 11 of 2012
Act 129	Pennsylvania Act 129 of 2008
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
AEPS	Pennsylvania Alternative Energy Portfolio Standards
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
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
ASC	Accounting Standards Codification
BGS	Basic Generation Service
Block Contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAMR	Federal Clean Air Mercury Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CES	Clean Energy Standard
CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
Conectiv	Conectiv, LLC, a wholly owned subsidiary of PHI and the parent of DPL and ACE
Conectiv Energy	Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries, which were sold to Calpine in July 2010
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
DCPSC	District of Columbia Public Service Commission
DC PLUG	District of Columbia Power Line Undergrounding
Default Electricity Supply	The supply of electricity by PHI's electric utility subsidiaries at regulated rates to retail customers who do not elect to purchase electricity from a competitive supplier, and which, depending on the jurisdiction, is also known as Standard Offer Service or BGS
DOE	United States Department of Energy
DOJ	United States Department of Justice
DPSC	Delaware Public Service Commission
DRP	Direct Stock Purchase and Dividend Reinvestment Plan
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDCs	Electric distribution companies
EDF	Electricite de France SA and its subsidiaries
EE&C	Energy Efficiency and Conservation/Demand Response
EGS	Electric Generation Supplier
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EmPower Maryland	A Maryland demand-side management program for Pepco and DPL

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
EPA	United States Environmental Protection Agency
EPSA	Electric Power Supply Association
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
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
GWh	Gigawatt hour
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
HSR Act	The Hart-Scott-Rodino Antitrust Improvements Act of 1976
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois Act	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
Integrys	Integrys Energy Services, Inc.
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
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LLRW	Low-Level Radioactive Waste
LT Plan	Long-term renewable resources procurement plan
LTIP	Long-Term Incentive Plan
MAPP	Mid-Atlantic Power Pathway
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
MRV	Market-Related Value
MW	Megawatt

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
n.m.	not meaningful
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGS	Natural Gas Supplier
NJBPU	New Jersey Board of Public Utilities
NJDEP	New Jersey Department of Environmental Protection
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
NUGs	Non-utility generators
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
NYPSC	New York Public Service Commission
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPC	Office of People’s Counsel
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
Preferred Stock	Originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value $0.01 per share
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PURTA	Pennsylvania Public Realty Tax Act
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RES	Retail Electric Suppliers
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
RMC	Risk Management Committee
ROE	Return on equity
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RSSA	Reliability Support Services Agreement
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Services
SEC	United States Securities and Exchange Commission
Senate Bill 1	Maryland Senate Bill 1
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SGIG	Smart Grid Investment Grant from DOE
SILO	Sale-In, Lease-Out
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPFPA	Security, Police and Fire Professionals of America
SPP	Southwest Power Pool
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
UGSOA	United Government Security Officers of America
Upstream	Natural gas exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council
ZEC	Zero Emission Credit
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 2016 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 24, 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 17, 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 public may read and copy any reports or other information that the Registrants file with the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services, the website maintained by the SEC at www.sec.gov and the Registrants' websites at www.exeloncorp.com. Information contained on the Registrants' websites shall not be deemed incorporated into, or to be a part of, this Report.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions, except per share data)	2017	2016	2017	2016
Operating revenues				
Competitive businesses revenues	$ 3,908	$ 3,234	$ 8,468	$ 7,708
Rate-regulated utility revenues	3,715	3,676	7,913	6,777
Total operating revenues	7,623	6,910	16,381	14,485
Operating expenses				
Competitive businesses purchased power and fuel	2,158	1,576	4,952	4,016
Rate-regulated utility purchased power and fuel	928	878	2,033	1,692
Operating and maintenance	2,971	2,505	5,431	5,341
Depreciation and amortization	915	941	1,811	1,626
Taxes other than income	420	394	857	720
Total operating expenses	7,392	6,294	15,084	13,395
Gain on sales of assets	1	31	5	40
Bargain purchase gain	—	—	226	—
Operating income	232	647	1,528	1,130
Other income and (deductions)				
Interest expense, net	(426)	(366)	(789)	(643)
Interest expense to affiliates	(10)	(10)	(20)	(20)
Other, net	205	144	488	258
Total other income and (deductions)	(231)	(232)	(321)	(405)
Income before income taxes	1	415	1,207	725
Income taxes	(72)	102	143	285
Equity in losses of unconsolidated affiliates	(9)	(7)	(18)	(10)
Net income	64	306	1,046	430
Net (loss) income attributable to noncontrolling interests and preference stock dividends	(16)	39	(30)	(10)
Net income attributable to common shareholders	$ 80	$ 267	$ 1,076	$ 440
Comprehensive income, net of income taxes				
Net income	$ 64	$ 306	$ 1,046	$ 430
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(14)	(12)	(28)	(23)
Actuarial loss reclassified to periodic benefit cost	49	46	98	93
Pension and non-pension postretirement benefit plan valuation adjustment	(2)	(1)	(58)	(3)
Unrealized (loss) gain on cash flow hedges	(1)	—	5	(7)
Unrealized (loss) gain on equity investments	—	(4)	3	(7)
Unrealized gain on foreign currency translation	2	—	3	6
Unrealized gain on marketable securities	1	2	2	—
Other comprehensive income	35	31	25	59
Comprehensive income	99	337	1,071	489
Comprehensive (loss) income attributable to noncontrolling interests and preference stock dividends	(16)	39	(32)	(10)
Comprehensive income attributable to common shareholders	$ 115	$ 298	$ 1,103	$ 499
Average shares of common stock outstanding:				
Basic	934	924	931	923
Diluted	936	926	932	926
Earnings per average common share:				
Basic	$ 0.09	$ 0.29	$ 1.16	$ 0.48
Diluted	$ 0.09	$ 0.29	$ 1.15	$ 0.48
Dividends declared per common share	$ 0.33	$ 0.32	$ 0.66	$ 0.63

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Six Months Ended June 30, 2017	2016
Cash flows from operating activities		
Net income	$ 1,046	$ 430
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	2,591	2,396
Impairment of long-lived assets and losses on regulatory assets	445	239
Gain on sales of assets	(5)	(40)
Bargain purchase gain	(226)	—
Deferred income taxes and amortization of investment tax credits	107	261
Net fair value changes related to derivatives	230	194
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(284)	(114)
Other non-cash operating activities	415	1,056
Changes in assets and liabilities:		
Accounts receivable	342	86
Inventories	(23)	89
Accounts payable and accrued expenses	(811)	(363)
Option premiums paid, net	(8)	(10)
Collateral (posted) received, net	(173)	710
Income taxes	58	470
Pension and non-pension postretirement benefit contributions	(325)	(258)
Other assets and liabilities	(481)	(593)
Net cash flows provided by operating activities	2,898	4,553
Cash flows from investing activities		
Capital expenditures	(3,845)	(4,489)
Proceeds from nuclear decommissioning trust fund sales	5,213	4,977
Investment in nuclear decommissioning trust funds	(5,339)	(5,094)
Acquisition of businesses, net	(212)	(6,642)
Proceeds from sales of long-lived assets	211	45
Proceeds from termination of direct financing lease investment	—	360
Change in restricted cash	1	15
Other investing activities	(9)	(49)
Net cash flows used in investing activities	(3,980)	(10,877)
Cash flows from financing activities		
Changes in short-term borrowings	422	(798)
Proceeds from short-term borrowings with maturities greater than 90 days	576	194
Repayments on short-term borrowings with maturities greater than 90 days	(510)	(315)
Issuance of long-term debt	981	3,174
Retirement of long-term debt	(1,049)	(217)
Dividends paid on common stock	(607)	(582)
Common stock issued from treasury stock	1,150	—
Proceeds from employee stock plans	43	17
Other financing activities	(23)	(4)
Net cash flows provided by financing activities	983	1,469
Decrease in cash and cash equivalents	(99)	(4,855)
Cash and cash equivalents at beginning of period	635	6,502
Cash and cash equivalents at end of period	$ 536	$ 1,647

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 536	$ 635
Restricted cash and cash equivalents	252	253
Deposit with IRS	1,250	1,250
Accounts receivable, net		
Customer	3,825	4,158
Other	958	1,201
Mark-to-market derivative assets	833	917
Unamortized energy contract assets	84	88
Inventories, net		
Fossil fuel and emission allowances	334	364
Materials and supplies	1,267	1,274
Regulatory assets	1,293	1,342
Other	1,600	930
Total current assets	12,232	12,412
Property, plant and equipment, net	72,748	71,555
Deferred debits and other assets		
Regulatory assets	9,945	10,046
Nuclear decommissioning trust funds	12,641	11,061
Investments	638	629
Goodwill	6,677	6,677
Mark-to-market derivative assets	464	492
Unamortized energy contract assets	419	447
Pledged assets for Zion Station decommissioning	75	113
Other	1,265	1,472
Total deferred debits and other assets	32,124	30,937
Total assets[(a)]	$ 117,104	$ 114,904

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 1,757	$ 1,267
Long-term debt due within one year	3,619	2,430
Accounts payable	3,134	3,441
Accrued expenses	2,878	3,460
Payables to affiliates	8	8
Regulatory liabilities	574	602
Mark-to-market derivative liabilities	244	282
Unamortized energy contract liabilities	340	407
Renewable energy credit obligation	308	428
PHI merger related obligation	126	151
Other	977	981
Total current liabilities	13,965	13,457
Long-term debt	30,315	31,575
Long-term debt to financing trusts	641	641
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	18,521	18,138
Asset retirement obligations	9,848	9,111
Pension obligations	4,082	4,248
Non-pension postretirement benefit obligations	1,955	1,848
Spent nuclear fuel obligation	1,139	1,024
Regulatory liabilities	4,398	4,187
Mark-to-market derivative liabilities	417	392
Unamortized energy contract liabilities	705	830
Payable for Zion Station decommissioning	—	14
Other	1,828	1,827
Total deferred credits and other liabilities	42,893	41,619
Total liabilities[a]	87,814	87,292
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2000 shares authorized, 960 shares and 924 shares outstanding at June 30, 2017 and December 31, 2016, respectively)	18,860	18,794
Treasury stock, at cost (2 shares and 35 shares at June 30, 2017 and December 31, 2016, respectively)	(123)	(2,327)
Retained earnings	11,442	12,030
Accumulated other comprehensive loss, net	(2,633)	(2,660)
Total shareholders' equity	27,546	25,837
Noncontrolling interests	1,744	1,775
Total equity	29,290	27,612
Total liabilities and shareholders' equity	$117,104	$ 114,904

(a) Exelon's consolidated assets include $8,385 million and $8,893 million at June 30, 2017 and December 31, 2016, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $3,021 million and $3,356 million at June 30, 2017 and December 31, 2016, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 3 — Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

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

(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, 2016	958,778	$18,794	$(2,327)	$12,030	$ (2,660)	$ 1,775	$ 27,612
Net income (loss)	—	—	—	1,076	—	(30)	1,046
Long-term incentive plan activity	2,494	23	—	—	—	—	23
Employee stock purchase plan issuances	648	43	—	—	—	—	43
Common stock issued from treasury stock	—	—	2,204	(1,054)	—	—	1,150
Changes in equity of noncontrolling interests	—	—	—	—	—	1	1
Common stock dividends	—	—	—	(610)	—	—	(610)
Other comprehensive income (loss), net of income taxes	—	—	—	—	27	(2)	25
Balance, June 30, 2017	961,920	$18,860	$ (123)	$11,442	$ (2,633)	$ 1,744	$ 29,290

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Operating revenues				
Operating revenues	$ 3,906	$ 3,231	$ 8,463	$ 7,702
Operating revenues from affiliates	268	358	598	627
Total operating revenues	4,174	3,589	9,061	8,329
Operating expenses				
Purchased power and fuel	2,156	1,575	4,952	4,015
Purchased power and fuel from affiliates	1	2	3	5
Operating and maintenance	1,824	1,369	3,132	2,665
Operating and maintenance from affiliates	186	161	365	332
Depreciation and amortization	334	408	637	697
Taxes other than income	140	118	282	244
Total operating expenses	4,641	3,633	9,371	7,958
Gain on sales of assets	—	31	4	31
Bargain purchase gain	—	—	226	—
Operating (loss) income	(467)	(13)	(80)	402
Other income and (deductions)				
Interest expense, net	(120)	(89)	(209)	(176)
Interest expense to affiliates	(9)	(10)	(19)	(20)
Other, net	181	117	440	210
Total other income and (deductions)	52	18	212	14
(Loss) income before income taxes	(415)	5	132	416
Income taxes	(158)	(31)	(31)	120
Equity in losses of unconsolidated affiliates	(9)	(8)	(19)	(11)
Net (loss) income	(266)	28	144	285
Net (loss) income attributable to noncontrolling interests	(16)	36	(30)	(17)
Net (loss) income attributable to membership interest	$ (250)	$ (8)	$ 174	$ 302
Comprehensive (loss) income, net of income taxes				
Net (loss) income	$ (266)	$ 28	$ 144	$ 285
Other comprehensive income (loss), net of income taxes				
Unrealized (loss) gain on cash flow hedges	(1)	1	5	(4)
Unrealized (loss) gain on equity investments	—	(2)	4	(4)
Unrealized gain on foreign currency translation	2	—	3	6
Unrealized gain on marketable securities	—	1	—	—
Other comprehensive income (loss)	1	—	12	(2)
Comprehensive (loss) income	(265)	28	156	283
Comprehensive (loss) income attributable to noncontrolling interests	(16)	36	(32)	(17)
Comprehensive (loss) income attributable to membership interest	$ (249)	$ (8)	$ 188	$ 300

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Cash flows from operating activities		
Net income	$ 144	$ 285
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	1,415	1,467
Impairment of long-lived assets	445	179
Gain on sales of assets	(4)	(31)
Bargain purchase gain	(226)	—
Deferred income taxes and amortization of investment tax credits	(173)	(59)
Net fair value changes related to derivatives	235	199
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(284)	(114)
Other non-cash operating activities	121	169
Changes in assets and liabilities:		
Accounts receivable	192	123
Receivables from and payables to affiliates, net	8	(77)
Inventories	(5)	57
Accounts payable and accrued expenses	(328)	(228)
Option premiums paid, net	(8)	(10)
Collateral (posted) received, net	(163)	720
Income taxes	(99)	41
Pension and non-pension postretirement benefit contributions	(116)	(117)
Other assets and liabilities	(180)	(217)
Net cash flows provided by operating activities	974	2,387
Cash flows from investing activities		
Capital expenditures	(1,189)	(2,051)
Proceeds from nuclear decommissioning trust fund sales	5,213	4,977
Investment in nuclear decommissioning trust funds	(5,339)	(5,094)
Acquisition of businesses, net	(212)	(1)
Proceeds from sale of long-lived assets	210	30
Change in restricted cash	(8)	25
Other investing activities	(32)	(96)
Net cash flows used in investing activities	(1,357)	(2,210)
Cash flows from financing activities		
Changes in short-term borrowings	(51)	—
Proceeds from short-term borrowings with maturities greater than 90 days	76	194
Repayments of short-term borrowings with maturities greater than 90 days	(10)	(15)
Issuance of long-term debt	779	173
Retirement of long-term debt	(295)	(131)
Changes in Exelon intercompany money pool	196	(429)
Distribution to member	(330)	(111)
Contribution from member	—	45
Other financing activities	(7)	39
Net cash flows provided by (used in) financing activities	358	(235)
Decrease in cash and cash equivalents	(25)	(58)
Cash and cash equivalents at beginning of period	290	431
Cash and cash equivalents at end of period	$ 265	$ 373

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 265	$ 290
Restricted cash and cash equivalents	166	158
Accounts receivable, net		
Customer	2,242	2,433
Other	447	558
Mark-to-market derivative assets	833	917
Receivables from affiliates	143	156
Unamortized energy contract assets	84	88
Inventories, net		
Fossil fuel and emission allowances	272	292
Materials and supplies	901	935
Other	1,241	701
Total current assets	6,594	6,528
Property, plant and equipment, net	25,261	25,585
Deferred debits and other assets		
Nuclear decommissioning trust funds	12,641	11,061
Investments	426	418
Goodwill	47	47
Mark-to-market derivative assets	453	476
Prepaid pension asset	1,590	1,595
Pledged assets for Zion Station decommissioning	75	113
Unamortized energy contract assets	418	447
Deferred income taxes	5	16
Other	620	688
Total deferred debits and other assets	16,275	14,861
Total assets[a]	$ 48,130	$ 46,974

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

(In millions)	June 30, 2017	December 31, 2016
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 716	$ 699
Long-term debt due within one year	1,828	1,117
Accounts payable	1,527	1,610
Accrued expenses	722	989
Payables to affiliates	132	137
Borrowings from Exelon intercompany money pool	251	55
Mark-to-market derivative liabilities	225	263
Unamortized energy contract liabilities	61	72
Renewable energy credit obligation	308	428
Other	294	313
Total current liabilities	6,064	5,683
Long-term debt	7,010	7,202
Long-term debt to affiliate	916	922
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,578	5,585
Asset retirement obligations	9,655	8,922
Non-pension postretirement benefit obligations	922	930
Spent nuclear fuel obligation	1,139	1,024
Payables to affiliates	2,871	2,608
Mark-to-market derivative liabilities	180	153
Unamortized energy contract liabilities	67	80
Payable for Zion Station decommissioning	—	14
Other	598	595
Total deferred credits and other liabilities	21,010	19,911
Total liabilities[(a)]	35,000	33,718
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	9,308	9,261
Undistributed earnings	2,119	2,275
Accumulated other comprehensive loss, net	(40)	(54)
Total member's equity	11,387	11,482
Noncontrolling interests	1,743	1,774
Total equity	13,130	13,256
Total liabilities and equity	$ 48,130	$ 46,974

(a) Generation's consolidated assets include $8,342 million and $8,817 million at June 30, 2017 and December 31, 2016, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include $2,900 million and $3,170 million at June 30, 2017 and December 31, 2016, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 3 — Variable Interest Entities.

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

	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2016	$ 9,261	$ 2,275	$ (54)	$ 1,774	$13,256
Net income (loss)	—	174	—	(30)	144
Changes in equity of noncontrolling interests	—	—	—	1	1
Distribution of net retirement benefit obligation to member	49	—	—	—	49
Allocation of tax benefit from member	(2)	—	—	—	(2)
Distribution to member	—	(330)	—	—	(330)
Other comprehensive income (loss), net of income taxes	—	—	14	(2)	12
Balance, June 30, 2017	$ 9,308	$ 2,119	$ (40)	$ 1,743	$13,130

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Operating revenues				
Electric operating revenues	$ 1,354	$ 1,283	$ 2,647	$ 2,527
Operating revenues from affiliates	3	3	9	8
Total operating revenues	1,357	1,286	2,656	2,535
Operating expenses				
Purchased power	360	326	689	668
Purchased power from affiliate	18	13	24	18
Operating and maintenance	312	318	620	623
Operating and maintenance from affiliate	65	50	127	113
Depreciation and amortization	211	190	419	379
Taxes other than income	72	65	144	141
Total operating expenses	1,038	962	2,023	1,942
Gain on sales of assets	—	—	—	5
Operating income	319	324	633	598
Other income and (deductions)				
Interest expense, net	(98)	(88)	(179)	(170)
Interest expense to affiliates	(3)	(3)	(6)	(7)
Other, net	4	3	8	7
Total other income and (deductions)	(97)	(88)	(177)	(170)
Income before income taxes	222	236	456	428
Income taxes	104	91	197	168
Net income	$ 118	$ 145	$ 259	$ 260
Comprehensive income	$ 118	$ 145	$ 259	$ 260

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

(In millions)	Six Months Ended June 30, 2017	2016
Cash flows from operating activities		
Net income	$ 259	$ 260
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	419	379
Deferred income taxes and amortization of investment tax credits	235	222
Other non-cash operating activities	58	83
Changes in assets and liabilities:		
Accounts receivable	12	(36)
Receivables from and payables to affiliates, net	(4)	1
Inventories	(2)	7
Accounts payable and accrued expenses	(182)	(42)
Collateral (posted) received, net	(8)	(10)
Income taxes	4	261
Pension and non-pension postretirement benefit contributions	(37)	(35)
Other assets and liabilities	34	38
Net cash flows provided by operating activities	788	1,128
Cash flows from investing activities		
Capital expenditures	(1,168)	(1,334)
Change in restricted cash	(10)	—
Other investing activities	12	21
Net cash flows used in investing activities	(1,166)	(1,313)
Cash flows from financing activities		
Changes in short-term borrowings	389	(259)
Issuance of long-term debt	—	1,200
Contributions from parent	184	113
Dividends paid on common stock	(211)	(183)
Other financing activities	(1)	(17)
Net cash flows provided by financing activities	361	854
(Decrease) increase in cash and cash equivalents	(17)	669
Cash and cash equivalents at beginning of period	56	67
Cash and cash equivalents at end of period	$ 39	$ 736

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 39	$ 56
Restricted cash	12	2
Accounts receivable, net		
Customer	529	528
Other	211	218
Receivables from affiliates	386	356
Inventories, net	160	159
Regulatory assets	182	190
Other	57	45
Total current assets	1,576	1,554
Property, plant and equipment, net	20,019	19,335
Deferred debits and other assets		
Regulatory assets	1,050	977
Investments	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,364	2,170
Prepaid pension asset	1,283	1,343
Other	237	325
Total deferred debits and other assets	7,565	7,446
Total assets	$29,160	$ 28,335

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	June 30, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 389	$ —
Long-term debt due within one year	1,125	425
Accounts payable	547	645
Accrued expenses	1,107	1,250
Payables to affiliates	67	65
Customer deposits	115	121
Regulatory liabilities	269	329
Mark-to-market derivative liability	19	19
Other	112	84
Total current liabilities	3,750	2,938
Long-term debt	5,911	6,608
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,600	5,364
Asset retirement obligations	122	119
Non-pension postretirement benefits obligations	229	239
Regulatory liabilities	3,585	3,369
Mark-to-market derivative liability	237	239
Other	541	529
Total deferred credits and other liabilities	10,314	9,859
Total liabilities	20,180	19,610
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	6,357	6,150
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	2,674	2,626
Total shareholders' equity	8,980	8,725
Total liabilities and shareholders' equity	$29,160	$ 28,335

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

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
Balance, December 31, 2016	$ 1,588	$6,150	$ (1,639)	$ 2,626	$ 8,725
Net income	—	—	259	—	259
Appropriation of retained earnings for future dividends	—	—	(259)	259	—
Common stock dividends	—	—	—	(211)	(211)
Contribution from parent	—	184	—	—	184
Parent tax matter indemnification	—	23	—	—	23
Balance, June 30, 2017	$ 1,588	$6,357	$ (1,639)	$ 2,674	$ 8,980

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Operating revenues				
Electric operating revenues	$ 548	$ 585	$ 1,138	$ 1,228
Natural gas operating revenues	80	77	285	273
Operating revenues from affiliates	2	2	3	4
Total operating revenues	630	664	1,426	1,505
Operating expenses				
Purchased power	136	130	292	295
Purchased fuel	27	23	113	100
Purchased power from affiliate	34	64	79	142
Operating and maintenance	153	157	326	333
Operating and maintenance from affiliates	37	33	72	72
Depreciation and amortization	71	67	141	134
Taxes other than income	35	38	74	80
Total operating expenses	493	512	1,097	1,156
Operating income	137	152	329	349
Other income and (deductions)				
Interest expense, net	(28)	(28)	(56)	(56)
Interest expense to affiliates	(3)	(3)	(6)	(6)
Other, net	2	2	3	4
Total other income and (deductions)	(29)	(29)	(59)	(58)
Income before income taxes	108	123	270	291
Income taxes	20	23	55	67
Net income	$ 88	$ 100	$ 215	$ 224
Comprehensive income	$ 88	$ 100	$ 215	$ 224

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

(In millions)	Six Months Ended June 30, 2017	2016
Cash flows from operating activities		
Net income	$ 215	$ 224
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	141	134
Deferred income taxes and amortization of investment tax credits	39	51
Other non-cash operating activities	22	27
Changes in assets and liabilities:		
Accounts receivable	26	(1)
Receivables from and payables to affiliates, net	(10)	(2)
Inventories	7	19
Accounts payable and accrued expenses	(30)	(19)
Income taxes	51	31
Pension and non-pension postretirement benefit contributions	(23)	(29)
Other assets and liabilities	(70)	(96)
Net cash flows provided by operating activities	368	339
Cash flows from investing activities		
Capital expenditures	(367)	(299)
Changes in Exelon intercompany money pool	121	—
Other investing activities	4	8
Net cash flows used in investing activities	(242)	(291)
Cash flows from financing activities		
Dividends paid on common stock	(144)	(139)
Other financing activities	—	(1)
Net cash flows used in financing activities	(144)	(140)
Decrease in cash and cash equivalents	(18)	(92)
Cash and cash equivalents at beginning of period	63	295
Cash and cash equivalents at end of period	$ 45	$ 203

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

(In millions)	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 45	$ 63
Restricted cash and cash equivalents	4	4
Accounts receivable, net		
Customer	258	306
Other	135	131
Receivables from affiliates	1	4
Receivable from Exelon intercompany pool	10	131
Inventories, net		
Fossil fuel	25	35
Materials and supplies	30	27
Prepaid utility taxes	77	9
Regulatory assets	46	29
Other	25	18
Total current assets	656	757
Property, plant and equipment, net	7,758	7,565
Deferred debits and other assets		
Regulatory assets	1,732	1,681
Investments	24	25
Receivable from affiliates	506	438
Prepaid pension asset	354	345
Other	11	20
Total deferred debits and other assets	2,627	2,509
Total assets	$11,041	$ 10,831

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	June 30, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Long-term debt due within one year	$ 500	$ —
Accounts payable	278	342
Accrued expenses	136	104
Payables to affiliates	50	63
Customer deposits	63	61
Regulatory liabilities	155	127
Other	31	30
Total current liabilities	1,213	727
Long-term debt	2,080	2,580
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,128	3,006
Asset retirement obligations	28	28
Non-pension postretirement benefits obligations	289	289
Regulatory liabilities	544	517
Other	89	85
Total deferred credits and other liabilities	4,078	3,925
Total liabilities	7,555	7,416
Commitments and contingencies		
Shareholder's equity		
Common stock	2,473	2,473
Retained earnings	1,012	941
Accumulated other comprehensive income, net	1	1
Total shareholder's equity	3,486	3,415
Total liabilities and shareholder's equity	$11,041	$ 10,831

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

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	Total Shareholder's Equity
Balance, December 31, 2016	$ 2,473	$ 941	$ 1	$ 3,415
Net income	—	215	—	215
Common stock dividends	—	(144)	—	(144)
Balance, June 30, 2017	$ 2,473	$ 1,012	$ 1	$ 3,486

See the Combined Notes to Consolidated Financial Statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	**2017**	**2016**	**2017**	**2016**
Operating revenues				
Electric operating revenues	$ 569	$ 582	$ 1,234	$ 1,260
Natural gas operating revenues	102	94	383	340
Operating revenues from affiliates	3	4	8	9
Total operating revenues	674	680	1,625	1,609
Operating expenses				
Purchased power	115	108	248	235
Purchased fuel	22	20	105	95
Purchased power from affiliate	97	133	231	304
Operating and maintenance	135	177	284	345
Operating and maintenance from affiliates	39	31	73	65
Depreciation and amortization	112	97	239	206
Taxes other than income	56	55	119	114
Total operating expenses	576	621	1,299	1,364
Operating income	98	59	326	245
Other income and (deductions)				
Interest expense, net	(22)	(20)	(46)	(40)
Interest expense to affiliates	(4)	(4)	(8)	(8)
Other, net	4	5	8	11
Total other income and (deductions)	(22)	(19)	(46)	(37)
Income before income taxes	76	40	280	208
Income taxes	31	6	111	73
Net income	45	34	169	135
Preference stock dividends	—	3	—	6
Net income attributable to common shareholder	$ 45	$ 31	$ 169	$ 129
Comprehensive income	$ 45	$ 34	$ 169	$ 135
Comprehensive income attributable to preference stock dividends	—	3	—	6
Comprehensive income attributable to common shareholder	$ 45	$ 31	$ 169	$ 129

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

(In millions)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Cash flows from operating activities		
Net income	$ 169	$ 135
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	239	206
Impairment of long-lived assets and losses on regulatory assets	—	52
Deferred income taxes and amortization of investment tax credits	99	17
Other non-cash operating activities	35	60
Changes in assets and liabilities:		
Accounts receivable	77	11
Receivables from and payables to affiliates, net	(7)	6
Inventories	(5)	6
Accounts payable and accrued expenses	(83)	(5)
Income taxes	26	46
Pension and non-pension postretirement benefit contributions	(47)	(42)
Other assets and liabilities	(31)	(3)
Net cash flows provided by operating activities	472	489
Cash flows from investing activities		
Capital expenditures	(405)	(392)
Change in restricted cash	18	5
Other investing activities	4	12
Net cash flows used in investing activities	(383)	(375)
Cash flows from financing activities		
Changes in short-term borrowings	40	(2)
Retirement of long-term debt	(41)	(39)
Dividends paid on preference stock	—	(6)
Dividends paid on common stock	(99)	(90)
Contributions from parent	—	21
Other financing activities	—	(2)
Net cash flows used in financing activities	(100)	(118)
Decrease in cash and cash equivalents	(11)	(4)
Cash and cash equivalents at beginning of period	23	9
Cash and cash equivalents at end of period	$ 12	$ 5

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 12	$ 23
Restricted cash and cash equivalents	6	24
Accounts receivable, net		
Customer	312	395
Other	75	102
Receivables from affiliates	1	—
Inventories, net		
Gas held in storage	31	30
Materials and supplies	42	38
Prepaid utility taxes	—	15
Regulatory assets	197	208
Other	4	7
Total current assets	680	842
Property, plant and equipment, net	7,283	7,040
Deferred debits and other assets		
Regulatory assets	495	504
Investments	13	12
Prepaid pension asset	310	297
Other	5	9
Total deferred debits and other assets	823	822
Total assets[(a)]	$8,786	$ 8,704

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 85	$ 45
Long-term debt due within one year	—	41
Accounts payable	205	205
Accrued expenses	100	175
Payables to affiliates	49	55
Customer deposits	113	110
Regulatory liabilities	67	50
Other	21	26
Total current liabilities	640	707
Long-term debt	2,282	2,281
Long-term debt to financing trust	252	252
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,322	2,219
Asset retirement obligations	22	21
Non-pension postretirement benefits obligations	201	205
Regulatory liabilities	90	110
Other	59	61
Total deferred credits and other liabilities	2,694	2,616
Total liabilities[(a)]	5,868	5,856
Commitments and contingencies		
Shareholders' equity		
Common stock	1,421	1,421
Retained earnings	1,497	1,427
Total shareholders' equity	2,918	2,848
Total liabilities and shareholders' equity	$8,786	$ 8,704

(a) BGE's consolidated assets include $26 million at December 31, 2016 of BGE's consolidated VIE that can only be used to settle the liabilities of the VIE. BGE's consolidated liabilities include $42 million at December 31, 2016 of BGE's consolidated VIE for which the VIE creditors do not have recourse to BGE. BGE has no interests in any VIEs as of June 30, 2017. See Note 3 — Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity
Balance, December 31, 2016	$ 1,421	$ 1,427	$ 2,848
Net income	—	169	169
Common stock dividends	—	(99)	(99)
Balance, June 30, 2017	$ 1,421	$ 1,497	$ 2,918

See the Combined Notes to Consolidated Financial Statements

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

	Successor				Predecessor
	Three Months Ended June 30,		Six Months Ended June 30,	March 24 to June 30,	January 1 to March 23,
(In millions)	2017	2016	2017	2016	2016
Operating revenues					
Electric operating revenues	$1,040	$1,030	$ 2,138	$ 1,120	$ 1,096
Natural gas operating revenues	22	26	87	28	57
Operating revenues from affiliates	12	10	23	23	—
Total operating revenues	1,074	1,066	2,248	1,171	1,153
Operating expenses					
Purchased power	259	263	547	288	471
Purchased fuel	9	9	39	11	26
Purchased power and fuel from affiliates	115	144	259	155	—
Operating and maintenance	231	223	454	670	294
Operating and maintenance from affiliates	38	23	70	25	—
Depreciation and amortization	165	160	332	174	152
Taxes other than income	110	108	221	123	105
Total operating expenses	927	930	1,922	1,446	1,048
Gain on sales of assets	1	—	1	—	—
Operating income (loss)	148	136	327	(275)	105
Other income and (deductions)					
Interest expense, net	(59)	(66)	(122)	(71)	(65)
Other, net	13	11	26	12	(4)
Total other income and (deductions)	(46)	(55)	(96)	(59)	(69)
Income (loss) before income taxes	102	81	231	(334)	36
Income taxes	36	29	26	(77)	17
Net income (loss)	$ 66	$ 52	$ 205	$ (257)	$ 19
Comprehensive income (loss), net of income taxes					
Net income (loss)	$ 66	$ 52	$ 205	$ (257)	$ 19
Other comprehensive income, net of income taxes					
Pension and non-pension postretirement benefit plans:					
Actuarial loss reclassified to periodic cost	—	—	—	—	1
Other comprehensive income	—	—	—	—	1
Comprehensive income (loss)	$ 66	$ 52	$ 205	$ (257)	$ 20

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Successor Six Months Ended June 30, 2017	Successor March 24 to June 30, 2016	Predecessor January 1 to March 23, 2016
Cash flows from operating activities			
Net income (loss)	$ 205	$ (257)	$ 19
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:			
Depreciation and amortization	332	174	152
Gain on sale of long-lived assets	(1)	—	—
Deferred income taxes and amortization of investment tax credits	59	(16)	19
Net fair value changes related to derivatives	—	—	18
Other non-cash operating activities	28	444	46
Changes in assets and liabilities:			
Accounts receivable	(3)	56	(28)
Receivables from and payables to affiliates, net	(7)	39	—
Inventories	(19)	—	(4)
Accounts payable and accrued expenses	(61)	(35)	42
Income taxes	87	22	12
Pension and non-pension postretirement benefit contributions	(68)	(2)	(4)
Other assets and liabilities	(149)	(237)	(8)
Net cash flows provided by operating activities	403	188	264
Cash flows from investing activities			
Capital expenditures	(671)	(339)	(273)
Proceeds from sales of long-lived assets	1	15	—
Changes in restricted cash	3	(34)	3
Purchases of investments	—	—	(68)
Other investing activities	—	8	(5)
Net cash flows used in investing activities	(667)	(350)	(343)
Cash flows from financing activities			
Changes in short-term borrowings	45	(537)	(121)
Proceeds from short-term borrowings with maturities greater than 90 days	—	—	500
Repayments of short-term borrowings with maturities greater than 90 days	(500)	(300)	—
Issuance of long-term debt	202	1	—
Retirement of long-term debt	(120)	(16)	(11)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan and employee-related compensation	—	—	2
Distribution to member	(131)	(124)	—
Contribution from member	751	1,088	—
Change in Exelon intercompany money pool	—	28	—
Other financing activities	(2)	(3)	2
Net cash flows provided by financing activities	245	137	372
(Decrease) increase in cash and cash equivalents	(19)	(25)	293
Cash and cash equivalents at beginning of period	170	319	26
Cash and cash equivalents at end of period	$ 151	$ 294	$ 319

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Successor June 30, 2017	Successor December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 151	$ 170
Restricted cash and cash equivalents	40	43
Accounts receivable, net		
Customer	484	496
Other	199	283
Receivable from affiliates	1	—
Inventories, net		
Gas held in storage	6	6
Materials and supplies	134	116
Regulatory assets	605	653
Other	86	71
Total current assets	1,706	1,838
Property, plant and equipment, net	12,014	11,598
Deferred debits and other assets		
Regulatory assets	2,715	2,851
Investments	132	133
Goodwill	4,005	4,005
Long-term note receivable	4	4
Prepaid pension asset	529	509
Deferred income taxes	6	6
Other	79	81
Total deferred debits and other assets	7,470	7,589
Total assets[(a)]	$21,190	$ 21,025

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Successor June 30, 2017	Successor December 31, 2016
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 67	$ 522
Long-term debt due within one year	160	253
Accounts payable	415	458
Accrued expenses	259	272
Payables to affiliates	86	94
Unamortized energy contract liabilities	279	335
Customer deposits	119	123
Merger related obligation	73	101
Regulatory liabilities	68	79
Other	36	47
Total current liabilities	1,562	2,284
Long-term debt	5,792	5,645
Deferred credits and other liabilities		
Regulatory liabilities	151	158
Deferred income taxes and unamortized investment tax credits	3,844	3,775
Asset retirement obligations	14	14
Non-pension postretirement benefit obligations	135	134
Unamortized energy contract liabilities	638	750
Other	213	249
Total deferred credits and other liabilities	4,995	5,080
Total liabilities[(a)]	12,349	13,009
Commitments and contingencies		
Member's equity		
Membership interest	8,828	8,077
Undistributed earnings (losses)	13	(61)
Total member's equity	8,841	8,016
Total liabilities and member's equity	$21,190	$ 21,025

(a) PHI's consolidated total assets include $43 million and $49 million at June 30, 2017 and December 31, 2016, respectively, of PHI's consolidated VIE that can only be used to settle the liabilities of the VIE. PHI's consolidated total liabilities include $121 million and $143 million at June 30, 2017 and December 31, 2016, respectively, of PHI's consolidated VIE for which the VIE creditors do not have recourse to PHI. See Note 3 — Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Membership Interest	Undistributed Earnings (Losses)	Member's Equity
Successor			
Balance, December 31, 2016	$ 8,077	$ (61)	$ 8,016
Net income	—	205	205
Distribution to member	—	(131)	(131)
Contribution from member	751	—	751
Balance, June 30, 2017	$ 8,828	$ 13	$ 8,841

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Operating revenues				
Electric operating revenues	$513	$508	$1,042	$1,058
Operating revenues from affiliates	1	1	3	3
Total operating revenues	514	509	1,045	1,061
Operating expenses				
Purchased power	74	64	157	256
Purchased power from affiliates	69	88	152	95
Operating and maintenance	106	100	208	389
Operating and maintenance from affiliates	14	9	26	10
Depreciation and amortization	78	70	160	144
Taxes other than income	90	89	180	182
Total operating expenses	431	420	883	1,076
Gain on sales of assets	1	8	1	8
Operating income (loss)	84	97	163	(7)
Other income and (deductions)				
Interest expense, net	(28)	(31)	(58)	(68)
Other, net	7	6	15	14
Total other income and (deductions)	(21)	(25)	(43)	(54)
Income (loss) before income taxes	63	72	120	(61)
Income taxes	20	23	19	(1)
Net income (loss)	$ 43	$ 49	$ 101	$ (60)
Comprehensive income (loss)	$ 43	$ 49	$ 101	$ (60)

See the Combined Notes to Consolidated Financial Statements

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2017	2016
Cash flows from operating activities		
Net income (loss)	$ 101	$ (60)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation and amortization	160	144
Deferred income taxes and amortization of investment tax credits	35	20
Gain on sale of long-lived assets	(1)	—
Other non-cash operating activities	—	158
Changes in assets and liabilities:		
Accounts receivable	(33)	(41)
Receivables from and payables to affiliates, net	(4)	47
Inventories	(10)	1
Accounts payable and accrued expenses	(45)	(19)
Income taxes	46	165
Pension and non-pension postretirement benefit contributions	(65)	(3)
Other assets and liabilities	(55)	(47)
Net cash flows provided by operating activities	129	365
Cash flows from investing activities		
Capital expenditures	(291)	(256)
Proceeds from sale of long-lived asset	1	12
Purchases of investments	—	(31)
Changes in restricted cash	(1)	(31)
Other investing activities	(2)	(1)
Net cash flows used in investing activities	(293)	(307)
Cash flows from financing activities		
Changes in short-term borrowings	(23)	(64)
Issuance of long-term debt	202	1
Retirement of long-term debt	(7)	(5)
Dividends paid on common stock	(58)	(55)
Contribution from parent	161	187
Other financing activities	(1)	—
Net cash flows provided by financing activities	274	64
Increase in cash and cash equivalents	110	122
Cash and cash equivalents at beginning of period	9	5
Cash and cash equivalents at end of period	$ 119	$ 127

See the Combined Notes to Consolidated Financial Statements

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 119	$ 9
Restricted cash and cash equivalents	34	33
Accounts receivable, net		
Customer	256	235
Other	114	150
Inventories, net	73	63
Regulatory assets	165	162
Other	7	32
Total current assets	768	684
Property, plant and equipment, net	5,759	5,571
Deferred debits and other assets		
Regulatory assets	682	690
Investments	102	102
Prepaid pension asset	332	282
Other	5	6
Total deferred debits and other assets	1,121	1,080
Total assets	$7,648	$ 7,335

See the Combined Notes to Consolidated Financial Statements

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 23
Long-term debt due within one year	18	16
Accounts payable	157	209
Accrued expenses	117	113
Payables to affiliates	70	74
Customer deposits	53	53
Regulatory liabilities	5	11
Merger related obligation	49	68
Other	16	29
Total current liabilities	485	596
Long-term debt	2,527	2,333
Deferred credits and other liabilities		
Regulatory liabilities	17	20
Deferred income taxes and unamortized investment tax credits	1,950	1,910
Non-pension postretirement benefit obligations	40	43
Other	125	133
Total deferred credits and other liabilities	2,132	2,106
Total liabilities	5,144	5,035
Commitments and contingencies		
Shareholder's equity		
Common stock	1,470	1,309
Retained earnings	1,034	991
Total shareholder's equity	2,504	2,300
Total liabilities and shareholder's equity	$7,648	$ 7,335

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2016	$ 1,309	$ 991	$ 2,300
Net income	—	101	101
Common stock dividends	—	(58)	(58)
Contribution from parent	161	—	161
Balance, June 30, 2017	$ 1,470	$ 1,034	$ 2,504

See the Combined Notes to Consolidated Financial Statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	**2017**	**2016**	**2017**	**2016**
Operating revenues				
Electric operating revenues	$ 258	$ 253	$ 553	$ 554
Natural gas operating revenues	22	26	87	85
Operating revenues from affiliates	2	2	4	4
Total operating revenues	282	281	644	643
Operating expenses				
Purchased power	64	70	141	216
Purchased fuel	9	9	38	35
Purchased power from affiliate	40	43	91	47
Operating and maintenance	66	73	133	277
Operating and maintenance from affiliates	8	5	15	6
Depreciation and amortization	40	38	79	76
Taxes other than income	14	13	28	28
Total operating expenses	241	251	525	685
Operating income (loss)	41	30	119	(42)
Other income and (deductions)				
Interest expense, net	(13)	(13)	(25)	(25)
Other, net	3	3	6	6
Total other income and (deductions)	(10)	(10)	(19)	(19)
Income (loss) before income taxes	31	20	100	(61)
Income taxes	12	8	24	(1)
Net income (loss)	$ 19	$ 12	$ 76	$ (60)
Comprehensive income (loss)	$ 19	$ 12	$ 76	$ (60)

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Six Months Ended June 30, 2017	2016
Cash flows from operating activities		
Net income (loss)	$ 76	$ (60)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation and amortization	79	76
Deferred income taxes and amortization of investment tax credits	33	23
Other non-cash operating activities	(3)	121
Changes in assets and liabilities:		
Accounts receivable	12	30
Receivables from and payables to affiliates, net	(2)	15
Inventories	(3)	1
Accounts payable and accrued expenses	18	(2)
Collateral received	—	1
Income taxes	13	66
Other assets and liabilities	(29)	(51)
Net cash flows provided by operating activities	194	220
Cash flows from investing activities		
Capital expenditures	(192)	(182)
Changes in restricted cash	—	(1)
Other investing activities	1	3
Net cash flows used in investing activities	(191)	(180)
Cash flows from financing activities		
Changes in short-term borrowings	25	(105)
Retirement of long-term debt	(14)	—
Dividends paid on common stock	(54)	(38)
Contribution from parent	—	113
Net cash flows used in financing activities	(43)	(30)
(Decrease) Increase in cash and cash equivalents	(40)	10
Cash and cash equivalents at beginning of period	46	5
Cash and cash equivalents at end of period	$ 6	$ 15

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DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 6	$ 46
Accounts receivable, net		
Customer	124	136
Other	49	63
Receivables from affiliates	—	3
Inventories, net		
Gas held in storage	6	7
Materials and supplies	36	32
Regulatory assets	71	59
Other	19	24
Total current assets	311	370
Property, plant and equipment, net	3,412	3,273
Deferred debits and other assets		
Regulatory assets	299	289
Goodwill	8	8
Prepaid pension asset	200	206
Other	5	7
Total deferred debits and other assets	512	510
Total assets	$4,235	$ 4,153

See the Combined Notes to Consolidated Financial Statements

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DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 25	$ —
Long-term debt due within one year	109	119
Accounts payable	125	88
Accrued expenses	35	36
Payables to affiliates	33	38
Customer deposits	35	36
Regulatory liabilities	43	43
Merger related obligation	3	13
Other	9	8
Total current liabilities	417	381
Long-term debt	1,217	1,221
Deferred credits and other liabilities		
Regulatory liabilities	95	97
Deferred income taxes and unamortized investment tax credits	1,092	1,056
Non-pension postretirement benefit obligations	20	19
Other	46	53
Total deferred credits and other liabilities	1,253	1,225
Total liabilities	2,887	2,827
Commitments and contingencies		
Shareholder's equity		
Common stock	764	764
Retained earnings	584	562
Total shareholder's equity	1,348	1,326
Total liabilities and shareholder's equity	$4,235	$ 4,153

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2016	$ 764	$ 562	$ 1,326
Net income	—	76	76
Common stock dividends	—	(54)	(54)
Balance, June 30, 2017	$ 764	$ 584	$ 1,348

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	**2017**	**2016**	**2017**	**2016**
Operating revenues				
Electric operating revenues	$ 269	$ 269	$ 543	$ 559
Operating revenues from affiliates	1	1	1	2
Total operating revenues	270	270	544	561
Operating expenses				
Purchased power	121	129	250	285
Purchased power from affiliates	7	12	16	13
Operating and maintenance	71	63	139	275
Operating and maintenance from affiliates	7	5	13	5
Depreciation and amortization	37	41	72	81
Taxes other than income	2	2	4	4
Total operating expenses	245	252	494	663
Gain on sale of assets	—	1	—	1
Operating income (loss)	25	19	50	(101)
Other income and (deductions)				
Interest expense, net	(15)	(16)	(30)	(32)
Other, net	2	2	4	5
Total other income and (deductions)	(13)	(14)	(26)	(27)
Income (loss) before income taxes	12	5	24	(128)
Income taxes	4	2	(12)	(31)
Net income (loss)	$ 8	$ 3	$ 36	$ (97)
Comprehensive income (loss)	$ 8	$ 3	$ 36	$ (97)

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

(In millions)	Six Months Ended June 30, 2017	2016
Cash flows from operating activities		
Net income (loss)	$ 36	$ (97)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation and amortization	72	81
Deferred income taxes and amortization of investment tax credits	(8)	(28)
Other non-cash operating activities	7	138
Changes in assets and liabilities:		
Accounts receivable	18	31
Receivables from and payables to affiliates, net	(6)	8
Inventories	(3)	(2)
Accounts payable and accrued expenses	3	6
Income taxes	11	181
Other assets and liabilities	(53)	(110)
Net cash flows provided by operating activities	77	208
Cash flows from investing activities		
Capital expenditures	(175)	(164)
Proceeds from sale of long-lived asset	—	2
Changes in restricted cash	2	1
Other investing activities	—	1
Net cash flows used in investing activities	(173)	(160)
Cash flows from financing activities		
Changes in short-term borrowings	42	(5)
Retirement of long-term debt	(17)	(22)
Dividends paid on common stock	(22)	(11)
Contribution from parent	—	139
Other financing activities	(1)	(1)
Net cash flows provided by financing activities	2	100
(Decrease) Increase in cash and cash equivalents	(94)	148
Cash and cash equivalents at beginning of period	101	3
Cash and cash equivalents at end of period	$ 7	$ 151

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

(In millions)	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 7	$ 101
Restricted cash and cash equivalents	7	9
Accounts receivable, net		
Customer	103	125
Other	46	44
Inventories, net	25	22
Prepaid utility taxes	37	—
Regulatory assets	89	96
Other	4	2
Total current assets	318	399
Property, plant and equipment, net	2,628	2,521
Deferred debits and other assets		
Regulatory assets	406	405
Long-term note receivable	4	4
Prepaid pension asset	79	84
Other	43	44
Total deferred debits and other assets	532	537
Total assets[a]	$3,478	$ 3,457

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	June 30, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 42	$ —
Long-term debt due within one year	33	35
Accounts payable	122	132
Accrued expenses	56	38
Payables to affiliates	23	29
Customer deposits	31	33
Regulatory liabilities	20	25
Merger related obligation	21	20
Other	8	8
Total current liabilities	356	320
Long-term debt	1,105	1,120
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	911	917
Non-pension postretirement benefit obligations	35	34
Other	23	32
Total deferred credits and other liabilities	969	983
Total liabilities[(a)]	2,430	2,423
Commitments and contingencies		
Shareholder's equity		
Common stock	912	912
Retained earnings	136	122
Total shareholder's equity	1,048	1,034
Total liabilities and shareholder's equity	$3,478	$ 3,457

(a) ACE's consolidated total assets include $30 million and $32 million at June 30, 2017 and December 31, 2016, respectively, of ACE's consolidated VIE that can only be used to settle the liabilities of the VIE. ACE's consolidated total liabilities include $108 million and $126 million at June 30, 2017 and December 31, 2016, respectively, of ACE's consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 3 — Variable Interest Entities.

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

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2016	$ 912	$ 122	$ 1,034
Net income	—	36	36
Common stock dividends	—	(22)	(22)
Balance, June 30, 2017	$ 912	$ 136	$ 1,048

See the Combined Notes to Consolidated Financial Statements

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	19	20
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	•	•	•		•			•	•	•	•		•	•			•	•	•	

1. Basis of Presentation (All Registrants)

Description of Business (All Registrants)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution and transmission businesses. Prior to March 23, 2016, Exelon's principal, wholly owned subsidiaries included Generation, ComEd, PECO and BGE. On March 23, 2016, in conjunction with the Amended and Restated Agreement and Plan of Merger (the PHI Merger Agreement), Purple Acquisition Corp, a wholly owned subsidiary of Exelon, merged with and into PHI, with PHI continuing as the surviving entity as a wholly owned subsidiary of Exelon. PHI is a utility services holding company engaged through its principal wholly owned subsidiaries, Pepco, DPL and ACE, in the energy distribution and transmission businesses. Refer to Note 4 — Mergers, Acquisitions and Dispositions for further information regarding the merger transaction.

The energy generation business includes:

- *Generation*: Generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions.

The energy delivery businesses include:

- *ComEd*: Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO*: Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE*: Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in central Maryland, including the City of Baltimore.

- *Pepco*: Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in the District of Columbia and major portions of Prince George's County and Montgomery County in Maryland.
- *DPL*: Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in northern Delaware.
- *ACE*: Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in southern New Jersey.

Basis of Presentation (All Registrants)

As a result of the acquisition of PHI, Exelon's financial reporting reflects PHI's consolidated financial results subsequent to the March 23, 2016, acquisition date. Exelon has accounted for the merger transaction applying the acquisition method of accounting, which requires that identifiable assets acquired and liabilities assumed by Exelon to be reported in Exelon's financial statements at fair value, with any excess of the purchase price over the fair value of net assets acquired reported as goodwill. Exelon has pushed-down the application of the acquisition method of accounting to the consolidated financial statements of PHI such that the assets and liabilities of PHI are similarly recorded at their respective fair values, and goodwill has been established as of the acquisition date. Accordingly, the consolidated financial statements of PHI for periods before and after the March 23, 2016, acquisition date reflect different bases of accounting, and the financial positions and the results of operations of the predecessor and successor periods are not comparable. The acquisition method of accounting has not been pushed down to PHI's wholly owned subsidiary utility registrants, Pepco, DPL and ACE.

For financial statement purposes, beginning on March 24, 2016, disclosures related to Exelon now also apply to PHI, Pepco, DPL and ACE, unless otherwise noted.

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

During preparation of the June 30, 2017 financial statements, errors were identified related to the Exelon, Generation, ComEd, PECO and BGE Consolidated Statements of Cash Flows for the three months ended March 31, 2017. These classification errors related to the presentation of changes in Account payable and accrued expenses and Accounts receivable within Cash flows provided by operating activities and Capital expenditures and Proceeds from sale of long-lived assets within Cash flows used in investing activities. These errors were corrected for the six months ended June 30, 2017, and will be revised within the first quarter 2018 Form 10-Q when the Consolidated Statements of Cash Flows for the three months ended March 31, 2017 will next be disclosed. As revised, the Cash flows provided by operating activities for the three months ended March 31, 2017 are $1,074 million, $420 million, $236 million, $106 million and $208 million for Exelon, Generation, ComEd, PECO and BGE, respectively, an increase (decrease) of $(127) million, $(320) million, $91 million, $42 million and $40 million for Exelon, Generation, ComEd, PECO and BGE, respectively, from the originally reported amounts. As revised, the Cash flows used in investing activities are $2,284 million, $892 million, $620 million, $69 million and $221 million for Exelon, Generation, ComEd, PECO and BGE, respectively, an increase (decrease) of $(127) million, $(320) million, $91 million, $42 million and $40 million for Exelon, Generation, ComEd, PECO and BGE, respectively, from the originally reported amounts. Management has concluded that the errors are not material to the previously issued financial statements.

The accompanying consolidated financial statements as of June 30, 2017 and 2016 and for the three and six 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, 2016 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, 2017. These Combined Notes to Consolidated Financial Statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations.

2. New Accounting Standards (All Registrants)

New Accounting Standards Issued and Not Yet Adopted: 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. Unless otherwise indicated, the Registrants are currently assessing the impacts such guidance may have (which could be material) on 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 such standards will not significantly impact the Registrants' financial reporting.

Revenue from Contracts with Customers (Issued May 2014 and subsequently amended to address implementation questions): Changes the criteria for recognizing revenue from a contract with a customer. The new revenue recognition guidance, including subsequent amendments, is effective for annual reporting periods beginning on or after December 15, 2017, with the option to early adopt the standard for annual periods beginning on or after December 15, 2016. Exelon has not early adopted this standard.

The new standard replaces existing guidance on revenue recognition, including most industry specific guidance, with a five step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries, and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows. In addition, the Registrants will be required to capitalize costs to acquire new contracts, and amortize such costs in a manner consistent with the transfer to the customer of the associated goods or services. The Registrants currently expense those costs as incurred. These expenses are not expected to be material to the Registrants' financial statements. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method).

The Registrants continue to assess the impacts this guidance may have on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. In conducting this assessment, the Registrants have performed the following key activities:

- Actively participate in the AICPA Power and Utilities Industry Task Force (Industry Task Force) process to identify implementation issues and support the development of related implementation guidance;

- Evaluate existing contracts and revenue streams for potential changes in the amounts and timing of recognizing revenues under the new guidance;
- Evaluate and select the transition method; and
- Develop and implement the approach and process for complying with the new revenue recognition disclosure requirements.

While there continues to be some ongoing activities in all of these areas, the Registrants have substantially completed the evaluation of their collective contracts and revenue streams, as well as the evaluation of the transition method. Based on the work completed thus far, the Registrants have reached the following preliminary conclusions:

- The Registrants expect to apply the new guidance using the full retrospective method;
- During the second quarter 2017, certain previously open implementation issues have been substantially resolved, including the collectability of utility tariff sale contracts and the accounting for bundled sales contracts. The Utility Registrants' tariff sale contracts, including those with lower credit quality customers, are generally deemed to be probable of collection under the guidance and, thus, the timing of revenue recognition will continue to be based on the electricity or natural gas supplied in the period, consistent with current practice. Revenues recognized from bundled sales contracts are generally expected to be recognized based on the invoice price, consistent with current practice; and
- Contributions in aid of construction are expected to be outside of the scope of the standard and, therefore, will continue to be accounted for as a reduction to Property, Plant, and Equipment.

The Registrants generally anticipate that the implementation of the new standard will not have a material impact on the amount and timing of revenue recognition. However, certain implementation issues continue to be evaluated through the Industry Task Force process that could have an impact on the Registrants' Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (Issued March 2017): The new standard will require significant changes to the accounting and presentation of pension and OPEB costs at the plan sponsor (i.e., Exelon) level. This guidance requires plan sponsors to separate net periodic pension cost and net periodic OPEB cost (together, net benefit cost) into the service cost component and other components; service cost will be presented as part of income from operations and the other components will be classified outside of income from operations on the Consolidated Statements of Operations and Comprehensive Income. Additionally, service cost is the only component eligible for capitalization (whereas under current GAAP, all components of net benefit cost are eligible for capitalization).

Exelon is currently evaluating the impact of this standard on its consolidated financial statements, including coordinating with its industry group and advisors. Generation, ComEd, PECO, BGE, BSC, PHI, Pepco, DPL, ACE and PHISCO participate in Exelon's single employer plans and apply multi-employer accounting. Multi-employer accounting is not impacted by this standard, so there is no impact on Exelon's subsidiary financial statements.

The standard is effective January 1, 2018 and requires retrospective application for the presentation of the service cost component and the other components of net benefit cost and prospective application for the capitalization of only the service cost component of net benefit cost. Exelon will not early adopt this standard.

Leases (Issued February 2016): Increases transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The guidance requires lessees to recognize both the right-of-use assets and lease liabilities in the balance sheet for most leases, whereas today only financing type lease liabilities (capital leases) are recognized in the balance sheet. This is expected to require significant changes to systems, processes and procedures in order to recognize and measure leases recorded on the balance sheet that are currently classified as operating leases. In addition, the definition of a lease has been revised in regards to when an arrangement conveys the right to control the use of the identified asset under the arrangement which may result in changes to the classification of an arrangement as a lease. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from current GAAP. The accounting applied by a lessor is largely unchanged from that applied under current GAAP. The standard is effective January 1, 2019. Early adoption is permitted, however the Registrants do not expect to early adopt the standard. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. Refer to Note 24 — Commitments and Contingencies of the Combined Notes to the Consolidated Financial Statements in the Exelon 2016 Form 10-K for additional information regarding operating leases.

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, for most debt instruments, requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption.

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 June 30, 2017. 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.

Clarifying the Definition of a Business (issued January 2017): Clarifies the definition of a business with the objective of addressing whether acquisitions should be accounted for as acquisitions of assets or as acquisitions of businesses. If substantially all the fair value of the assets acquired is concentrated in a single identifiable asset or a group of similar identifiable assets, the set of transferred assets and activities is not a business. If the fair value of the assets acquired is not concentrated in a single identifiable asset or a group of similar identifiable assets, then an entity must evaluate whether an input and a substantive process exist, which together significantly contribute to the ability to produce outputs. The standard also revises the definition of outputs to focus on goods and services to customers. The standard could result in more acquisitions being accounted for as asset acquisitions. The standard is effective January 1, 2018, with early adoption permitted, and will be applied prospectively.

Intra-Entity Transfers of Assets Other Than Inventory (Issued October 2016): Requires entities to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs (current GAAP prohibits the recognition of current and deferred income taxes for an intra-entity asset transfer until the asset has been sold to an outside party). The standard is effective January 1, 2018 with early adoption permitted. The guidance is required to be applied on a modified retrospective basis through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments (Issued August 2016) and Restricted Cash (Issued November 2016): In 2016, the FASB issued two standards impacting the Statement of Cash Flows. The first adds or clarifies guidance on the classification of certain cash receipts and payments on the statement of cash flows as follows: debt prepayment or extinguishment costs, settlement of zero-coupon bonds, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies and bank-owned life insurance policies, distributions received from equity method investees, beneficial interest in securitization transactions, and the application of the predominance principle to separately identifiable cash flows. The second states that amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows (instead of being presented as cash flow activities). Exelon will adopt both standards on January 1, 2018 on a retrospective basis. Adoption of the second standard will result in a change in presentation of restricted cash on the face of the Statement of Cash Flows; otherwise the Registrants expect that adoption of the guidance will have insignificant impacts on the Registrants' Consolidated Statements of Cash Flows and disclosures.

Recognition and Measurement of Financial Assets and Financial Liabilities (Issued January 2016): (i) Requires all investments in equity securities, including other ownership interests such as partnerships, unincorporated joint ventures and limited liability companies, to be carried at fair value through net income, (ii) requires an incremental recognition and disclosure requirement related to the presentation of fair value changes of financial liabilities for which the fair value option has been elected, (iii) amends several disclosure requirements, including the methods and significant assumptions used to estimate fair value or a description of the changes in the methods and assumptions used to estimate fair value, and (iv) requires disclosure of the fair value of financial assets and liabilities measured at amortized cost at the amount that would be received to sell the asset or paid to transfer the liability. The standard is effective January 1, 2018 with early adoption permitted. The guidance is required to be applied retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of adoption (modified retrospective method).

3. 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 June 30, 2017 and December 31, 2016, Exelon, Generation, BGE, PHI and ACE collectively consolidated seven and nine VIEs or VIE groups, respectively, for which the applicable Registrant was the primary beneficiary (*see Consolidated Variable Interest Entities below)*. As of June 30, 2017 and December 31, 2016, Exelon and Generation collectively had significant interests in seven and eight, respectively, 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)*.

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

Consolidated Variable Interest Entities

RSB BondCo LLC (BondCo) is a special purpose bankruptcy remote limited liability company formed by BGE to acquire, hold, issue and service bonds secured by rate stabilization property. BGE is required to remit all payments it receives from all residential customers through non-bypassable, rate stabilization charges to BondCo. On April 3, 2017, the rate stabilization bonds were fully redeemed. During the three and six months ended June 30, 2017, BGE remitted $3 million and $22 million to BondCo, respectively, with all of the final $3 million remitted through June 30, 2017 after the bonds were fully redeemed. During the three and six months ended June 30, 2016, BGE remitted $21 million and $42 million to BondCo, respectively.

Upon the redemption of the bonds, BondCo no longer meets the definition of a variable interest entity and is removed from the list of consolidated VIEs noted below. However, BondCo will continue to be consolidated by BGE under the voting interest model.

During 2009, Constellation formed a retail gas group to enter into a collateralized gas supply agreement with a third-party gas supplier. Upon assessment, the retail gas group was determined to be a VIE because there was not sufficient equity to fund the group's activities without additional credit support and a $75 million parental guarantee provided by Generation. As the primary beneficiary, Generation consolidated the retail gas group. During the second quarter of 2017, the collateral structure was terminated with the third-party gas supplier except for the $75 million parental guarantee provided by Generation. Although the parental guarantee will remain, this is considered customary and reasonable for the unsecured position Generation has with the third-party gas supplier. As a result of the termination, the retail gas group no longer meets the definition of a VIE and is removed from the list of consolidated VIEs noted below. However, the retail gas group will continue to be consolidated by Generation under the voting interest model.

Exelon's, Generation's, PHI's and ACE's consolidated VIEs consist of:

- A group of solar project limited liability companies formed by Generation to build, own and operate solar power facilities,
- several wind project companies designed by Generation to develop, construct and operate wind generation facilities,
- a group of companies formed by Generation to build, own and operate other generating facilities,
- certain retail power and gas companies for which Generation is the sole supplier of energy,
- CENG,
- 2015 ESA Investco, LLC, a company that holds an equity method investment in a distributed energy company, and
- 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 June 30, 2017 and December 31, 2016, ComEd, PECO, Pepco and DPL did not have any material consolidated VIEs.

As of June 30, 2017 and December 31, 2016, Exelon, Generation, PHI and ACE provided the following support to their respective consolidated VIEs:

- Generation provides operating and capital funding to the solar and wind entities for ongoing construction, operations and maintenance of the solar and wind power facilities and there is limited recourse to Generation related to certain solar and wind entities.

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

- Generation provides approximately $30 million in credit support for the retail power and gas companies for which Generation is the sole supplier of energy.
- Generation provides operating and capital funding to the other generating facilities for ongoing construction, operations and maintenance and provides a parental guarantee of up to $275 million in support of the payment obligations related to the Engineering, Procurement and Construction contract in support of one of its other generating facilities.
- Generation and Exelon, where indicated, provide the following support to CENG (see Note 5 —Investment in Constellation Energy Nuclear Group, LLC and Note 27—Related Party Transactions of the Exelon 2016 Form 10-K for additional information regarding Generation's and Exelon's transactions with CENG):
  - under the NOSA, Generation conducts all activities related to the operation of the CENG nuclear generation fleet owned by CENG subsidiaries (the CENG fleet) and provides corporate and administrative services for the remaining life and decommissioning of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF,
  - under the Power Services Agency Agreement (PSAA), Generation provides scheduling, asset management and billing services to the CENG fleet for the remaining operating life of the CENG nuclear plants,
  - under power purchase agreements 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 Reliability Support Services Agreement (RSSA), through the end of March 31, 2017. With the expiration of the RSSA, the PPA was reinstated beginning April 1, 2017 (see Note 5 — Regulatory Matters for additional details),
  - Generation provided a $400 million loan to CENG. As of June 30, 2017, the remaining obligation is $324 million, including accrued interest, which reflects the principal payment made in January 2015,
  - 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 17 — Commitments and Contingencies for more details),
  - Generation and EDF share in the $637 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance,
  - Generation provides a guarantee of approximately $8 million associated with hazardous waste management facilities and underground storage tanks. In addition, EDF executed a reimbursement agreement that provides reimbursement to Exelon for 49.99% of any amounts paid by Generation under this guarantee,
  - Generation and EDF are the members-insured with Nuclear Electric Insurance Limited and have assigned the loss benefits under the insurance and the NEIL premium costs to CENG and guarantee the obligations of CENG under these insurance programs in proportion to their respective member interests (see Note 17 — Commitments and Contingencies for more details), 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.

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

- 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 NJBPU in an amount sufficient to fund the principal and interest payments on transition bonds and related taxes, expenses and fees. During the three and six months ended June 30, 2017, ACE transferred $8 million and $27 million to ATF, respectively. During the three and six months ended June 30, 2016, ACE transferred $12 million and $26 million to ATF, respectively.

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 June 30, 2017 and December 31, 2016 are as follows:

	June 30, 2017				December 31, 2016				
	Exelon[(a)]	Generation	*Successor* PHI [(a)]	ACE	Exelon[(a)(b)]	Generation	BGE	*Successor* PHI [(a)]	ACE
Current assets	$ 512	$ 501	$ 11	$ 7	$ 954	$ 916	$ 23	$ 14	$ 9
Noncurrent assets	8,617	8,585	32	23	8,563	8,525	3	35	23
Total assets	$ 9,129	$ 9,086	$ 43	$ 30	$ 9,517	$ 9,441	$ 26	$ 49	$ 32
Current liabilities	$ 573	$ 535	$ 38	$ 34	$ 885	$ 802	$ 42	$ 42	$ 37
Noncurrent liabilities	2,723	2,640	83	74	2,713	2,612	—	101	89
Total liabilities	$ 3,296	$ 3,175	$ 121	$108	$ 3,598	$ 3,414	$ 42	$ 143	$126

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

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

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 June 30, 2017 and December 31, 2016, these assets and liabilities primarily consisted of the following:

	June 30, 2017				December 31, 2016				
	Exelon (a)	Generation	Successor PHI (a)	ACE	Exelon(a)(b)	Generation	BGE	Successor PHI (a)	ACE
Cash and cash equivalents	$ 68	$ 68	$ —	$ —	$ 150	$ 150	$ —	$ —	$ —
Restricted cash	55	48	7	7	59	27	23	9	9
Accounts receivable, net									
Customer	106	106	—	—	371	371	—	—	—
Other	24	24	—	—	48	48	—	—	—
Mark-to-market derivatives assets	—	—	—	—	31	31	—	—	—
Inventory									
Materials and supplies	193	193	—	—	199	199	—	—	—
Other current assets	38	34	4	—	50	44	—	5	—
Total current assets	484	473	11	7	908	870	23	14	9
Property, plant and equipment, net	5,293	5,293	—	—	5,415	5,415	—	—	—
Nuclear decommissioning trust funds	2,341	2,341	—	—	2,185	2,185	—	—	—
Goodwill	—	—	—	—	47	47	—	—	—
Mark-to-market derivative assets	—	—	—	—	23	23	—	—	—
Other noncurrent assets	267	235	32	23	315	277	3	35	23
Total noncurrent assets	7,901	7,869	32	23	7,985	7,947	3	35	23
Total assets	$ 8,385	$ 8,342	$ 43	$ 30	$ 8,893	$ 8,817	$ 26	$ 49	$ 32
Long-term debt due within one year	$ 191	$ 154	$ 37	$ 33	$ 181	$ 99	$ 41	$ 40	$ 35
Accounts payable	80	80	—	—	269	269	—	—	—
Accrued expenses	48	47	1	1	119	116	1	2	2
Mark-to-market derivative liabilities	—	—	—	—	60	60	—	—	—
Unamortized energy contract liabilities	16	16	—	—	15	15	—	—	—
Other current liabilities	5	5	—	—	30	30	—	—	—
Total current liabilities	340	302	38	34	674	589	42	42	37
Long-term debt	616	533	83	74	641	540	—	101	89
Asset retirement obligations	1,954	1,954	—	—	1,904	1,904	—	—	—
Pension obligation(c)	—	—	—	—	9	9	—	—	—
Unamortized energy contract liabilities	13	13	—	—	22	22	—	—	—
Other noncurrent liabilities	98	98	—	—	106	106	—	—	—
Total noncurrent liabilities	2,681	2,598	83	74	2,682	2,581	—	101	89
Total liabilities	$ 3,021	$ 2,900	$ 121	$108	$ 3,356	$ 3,170	$ 42	$ 143	$126

(a) Includes certain purchase accounting adjustments not pushed down to the ACE standalone entity.
(b) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(c) Includes the CNEG retail gas pension obligation, which is presented as a net asset balance within the Prepaid pension asset line item on Generation's Consolidated Balance Sheets. See Note 13 — Retirement Benefits for additional details.

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 on Exelon's and Generation's Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominantly 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.

The Registrants' 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 and energy generating facilities for which Generation has concluded that consolidation is not required.

As of June 30, 2017 and December 31, 2016, Exelon and Generation had significant unconsolidated variable interests in seven and eight VIEs, respectively, for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity investments and certain commercial agreements. The decrease in the number of unconsolidated VIEs is due to the sale of an equity investment in an energy generating facility. Exelon and Generation only include unconsolidated VIEs that are individually material in the tables below. However, Generation has several individually immaterial VIEs that in aggregate represent a total investment of $16 million. These immaterial VIEs are equity and debt securities in energy development companies. The maximum exposure to loss related to these securities is limited to the $16 million included in Investments on Exelon's and Generation's Consolidated Balance Sheets. 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.

In June 2015, 2015 ESA Investco, LLC, then a wholly owned subsidiary of Generation, entered into an arrangement to purchase a 90% equity interest and 99% of the tax attributes of a distributed energy company, which is an unconsolidated VIE. In November 2015, Generation sold 69% of its equity interest in 2015 ESA Investco, LLC to a tax equity investor. Generation and the tax equity investor contributed a total of $227 million of equity incrementally from inception through the first quarter of 2017 in proportion of their ownership interests. Generation and the tax equity investor provided a parental guarantee of up to $275 million in proportion to their ownership interests in support of 2015 ESA Investco, LLC's obligation to make equity contributions to the distributed energy company. As all equity contributions were made as of the first quarter 2017, there is no further payment obligation under the parental guarantee.

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

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

June 30, 2017	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[a]	$ 641	$ 529	$1,170
Total liabilities[a]	64	229	293
Exelon's ownership interest in VIE[a]	—	268	268
Other ownership interests in VIE[a]	577	32	609
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	268	268
Contract intangible asset	9	—	9
Debt and payment guarantees	—	—	—
Net assets pledged for Zion Station decommissioning[b]	6	—	6

December 31, 2016	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[a]	$ 638	$ 567	$1,205
Total liabilities[a]	215	287	502
Exelon's ownership interest in VIE[a]	—	248	248
Other ownership interests in VIE[a]	423	32	455
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	264	264
Contract intangible asset	9	—	9
Debt and payment guarantees	—	3	3
Net assets pledged for Zion Station decommissioning[b]	9	—	9

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon's or Generation's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.
(b) These items represent amounts on Exelon's and Generation's Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $75 million and $113 million as of June 30, 2017 and December 31, 2016, respectively; offset by payables to ZionSolutions LLC of $69 million and $104 million as of June 30, 2017 and December 31, 2016, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE. See Note 12 — Nuclear Decommissioning for additional details.

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.

4. Mergers, Acquisitions and Dispositions (Exelon, Generation, PHI and Pepco)

Acquisition of James A. FitzPatrick Nuclear Generating Station (Exelon and Generation)

On March 31, 2017, Generation acquired the 838 MW single-unit James A. FitzPatrick (FitzPatrick) nuclear generating station located in Scriba, New York from Entergy Nuclear FitzPatrick LLC (Entergy) for a total purchase price of $293 million, which consisted of a cash purchase price of $110 million and a net cost reimbursement to and on behalf of Entergy of $183 million. As part of the acquisition agreements, Generation provided nuclear fuel and reimbursed Entergy for incremental costs to prepare for and conduct a plant refueling outage; and Generation reimbursed Entergy for incremental costs to operate and maintain the plant for the period after the refueling outage through the acquisition closing date. These reimbursements covered costs that Entergy otherwise would have avoided had it shut down the plant as originally intended in January 2017. The amounts reimbursed by Generation were offset by FitzPatrick's electricity and capacity sales revenues for this same post-outage period. As part of the transaction, Generation received the FitzPatrick NDT fund assets and assumed the obligation to decommission FitzPatrick. The NRC license for FitzPatrick expires in 2034. As of June 30, 2017, Generation had remitted purchase price consideration of $293 million (including $239 million of cash and $54 million of nuclear fuel) to and on behalf of Entergy.

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

The following table summarizes the acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for the FitzPatrick acquisition by Generation as of June 30, 2017:

Cash paid for purchase price	$ 110
Cash paid for net cost reimbursement	129
Nuclear fuel transfer	54
Total consideration transferred	$ 293
Identifiable assets acquired and liabilities assumed	
Current assets	$ 58
Property, plant and equipment	278
Nuclear decommissioning trust funds	807
Other assets[(a)]	114
Total assets	$1,257
Current liabilities	$ 7
Asset retirement obligations	417
Pension and OPEB obligations	49
Deferred income taxes	144
Spent nuclear fuel obligation	110
Other liabilities	11
Total liabilities	$ 738
Total net identifiable assets, at fair value	$ 519
Bargain purchase gain (after-tax)	$ 226

(a) Includes a $110 million asset associated with a contractual right to reimbursement from the New York Power Authority (NYPA), a prior owner of FitzPatrick, associated with the DOE one-time fee obligation. See Note 24-Commitments and Contingencies of the Exelon 2016 Form 10-K for additional background regarding SNF obligations to the DOE.

The after-tax bargain purchase gain of $226 million is included within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and reflects differences in strategies between Generation and Entergy for the intended use and ultimate decommissioning of the plant.

The fair values of FitzPatrick's assets and liabilities were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing), discount rates reflecting risk inherent in the future cash flows and future power and fuel market prices. The valuations performed to assess the fair value of certain assets acquired and liabilities assumed are preliminary. Accounting guidance provides that the allocation of the purchase price may be modified up to one year from the date of the acquisition to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date; however, Generation expects to finalize these amounts by the end of 2017. The significant assets and liabilities for which preliminary valuation amounts are recognized at June 30, 2017 include the fair value of the decommissioning ARO, pension and OPEB obligations and related deferred tax liabilities. Any changes to the fair value assessments may materially impact the purchase price allocation and the amount of the recorded bargain purchase gain.

For the three and six months ended June 30, 2017, Exelon and Generation incurred $16 million and $47 million, respectively, of merger and integration related costs which are included within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Merger with Pepco Holdings, Inc. (Exelon)

Description of Transaction

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

Regulatory Matters

Approval of the merger in Delaware, New Jersey, Maryland and the District of Columbia was conditioned upon Exelon and PHI agreeing 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 speaking, requires allocation of merger benefits proportionally across all the jurisdictions.

During the third and fourth quarters of 2016, Exelon and PHI filed proposals in Delaware, New Jersey and Maryland for amounts and allocations reflecting the application of the most favored nation provision, resulting in a total nominal cost of commitments of $513 million, excluding renewable generation commitments (approximately $444 million on a net present value basis amount, excluding renewable generation commitments and charitable contributions). These filings reflect agreements reached with certain parties to the merger proceedings in these jurisdictions. In 2016, the DPSC and NJBPU approved the amounts and allocations of the additional merger benefits for Delaware and New Jersey, respectively. On April 12, 2017, the MDPSC issued an order approving the amounts of the additional merger benefits for Maryland, but amending the proposed allocations of the benefits. The amended allocations do not have a material effect on any of the Registrants' financial statements. No changes in commitment cost levels are required in the District of Columbia.

During the second quarter of 2017, Exelon finalized the application of $8 million funding for low- and moderate-income customers in the Pepco Maryland and DPL Maryland service territories. This resulted in an adjustment to merger commitment costs recorded at Exelon Corporate, Pepco, and DPL. Exelon Corporate recorded an increase of $8 million and Pepco and DPL recorded a decrease of $6 million and $2 million, respectively, in Operating and maintenance expense.

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

The following amounts represent total commitment costs for Exelon, PHI, Pepco, DPL and ACE that have been recorded since the acquisition date:

Description	Expected Payment Period	Pepco	DPL	ACE	*Successor* PHI	Exelon
Rate credits	2016 — 2017	$ 91	$ 67	$ 101	$ 259	$ 259
Energy efficiency	2016 — 2021	—	—	—	—	122
Charitable contributions	2016 — 2026	28	12	10	50	50
Delivery system modernization	Q2 2017	—	—	—	—	22
Green sustainability fund	Q2 2017	—	—	—	—	14
Workforce development	2016 — 2020	—	—	—	—	17
Other		1	5	—	6	29
Total		$ 120	$ 84	$ 111	$ 315	$ 513

Pursuant to the orders approving the merger, Exelon made $73 million, $46 million and $49 million of equity contributions to Pepco, DPL and ACE, respectively, in the second quarter of 2016 to fund the after-tax amounts of the customer bill credit and the customer base rate credit commitments.

In addition, Exelon is committed to develop or to assist in the commercial development of approximately 37 MWs of new generation in Maryland, District of Columbia, and Delaware, 27 MWs of which are expected to be completed by 2018. These investments are expected to total approximately $137 million, are expected to be primarily capital in nature, and will generate future earnings at Exelon and Generation. Investment costs will be recognized as incurred and recorded on Exelon's and Generation's financial statements. Exelon has also committed to purchase 100 MWs of wind energy in PJM, to procure 120 MWs of wind RECs for the purpose of meeting Delaware's renewable portfolio standards, and to maintain and promote energy efficiency and demand response programs in the PHI jurisdictions.

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.

In July 2015, the OPC, Public Citizen, Inc., the Sierra Club and the Chesapeake Climate Action Network (CCAN) filed motions to stay the MDPSC order approving the merger. The Circuit Court judge issued an order denying the motions for stay on August 12, 2015. On January 8, 2016, the Circuit Court judge affirmed the MDPSC's order approving the merger and denied the petitions for judicial review filed by the OPC, the Sierra Club, CCAN and Public Citizen, Inc. On January 19, 2016, the OPC filed a notice of appeal to the Maryland Court of Special Appeals, and on January 21, the Sierra Club and CCAN filed notices of appeal. On January 27, 2017, the Maryland Court of Special Appeals affirmed the Circuit Court's judgment that the MDPSC did not err in approving the merger. The OPC and Sierra Club filed petitions seeking further review in the Court of Appeals of Maryland, which is the highest court in Maryland. On June 21, 2017, the Court of Appeals granted discretionary review of the January 27, 2017 decision by the Maryland Court of Special Appeals. The Maryland Court of Appeals will review the OPC argument that the MDPSC did not properly consider the acquisition premium paid to PHI shareholders under Maryland's merger approval standard and the Sierra Club's argument that the merger would harm the renewable and distributed generation markets. The two lower courts examining these issues rejected these arguments, which Exelon believes are without merit. The petitioners' briefs were filed on July 31, 2017, and briefs of Exelon and the MDPSC are due on August 30, 2017. The case is set for oral argument in October 2017.

Between March 25, 2016 and April 22, 2016, various parties filed motions with the DCPSC to reconsider its March 23, 2016 order approving the merger. On June 17, 2016, the DCPSC denied all motions. In August 2016, the District of Columbia Office of People's Counsel, the District of Columbia Government, and Public Citizen jointly with DC Sun each filed petitions for judicial review of the DCPSC's March 23, 2016 order with the District of Columbia Court of Appeals. On July 20, 2017, the Court issued an opinion rejecting all of appellants' arguments and affirming the Commission's decision approving the merger.

Accounting for the Merger Transaction

The total purchase price consideration of approximately $7.1 billion for the PHI Merger consisted of cash paid to PHI shareholders, cash paid for PHI preferred securities and cash paid for PHI stock-based compensation equity awards as follows:

(In millions of dollars, except per share data)	Total Consideration
Cash paid to PHI shareholders at $27.25 per share (254 million shares outstanding at March 23, 2016)	$ 6,933
Cash paid for PHI preferred stock	180
Cash paid for PHI stock-based compensation equity awards[(a)]	29
Total purchase price	$ 7,142

(a) PHI's unvested time-based restricted stock units and performance-based restricted stock units issued prior to April 29, 2014 were immediately vested and paid in cash upon the close of the merger. PHI's remaining unvested time-based restricted stock units as of the close of the merger were cancelled. There were no remaining unvested performance-based restricted stock units as of the close of the merger.

PHI shareholders received $27.25 of cash in exchange for each share of PHI common stock outstanding as of the effective date of the merger. In connection with the Merger Agreement, Exelon entered into a Subscription Agreement under which it purchased $180 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities of PHI prior to December 31, 2015. On March 23, 2016, the preferred securities were cancelled for no consideration to Exelon, and accordingly, the $180 million cash consideration previously paid to acquire the preferred securities was treated as purchase price consideration.

The preliminary valuations performed in the first quarter of 2016 were updated in the second, third, and fourth quarters of 2016. There were no adjustments to the purchase price allocation in the first quarter of 2017 and the purchase price allocation is now final.

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

Exelon applied push-down accounting to PHI, and accordingly, the PHI assets acquired and liabilities assumed were recorded at their estimated fair values on Exelon's and PHI's Consolidated Balance Sheets as of March 23, 2016, as follows:

Purchase Price Allocation (a)	
Current assets	$ 1,441
Property, plant and equipment	11,088
Regulatory assets	5,015
Other assets	248
Goodwill	4,005
Total assets	$21,797
Current liabilities	$ 2,752
Unamortized energy contracts	1,515
Regulatory liabilities	297
Long-term debt, including current maturities	5,636
Deferred income taxes	3,447
Pension and OPEB obligations	821
Other liabilities	187
Total liabilities	$14,655
Total purchase price	$ 7,142

(a) Amounts shown reflect the final purchase price allocation and the correction of a reporting error identified and corrected in the second quarter of 2016. The error had resulted in a gross up of certain assets and liabilities related to legacy PHI intercompany and income tax receivable and payable balances.

On its successor financial statements, PHI has recorded, beginning March 24, 2016, Membership interest equity of $7.2 billion, which is greater than the total $7.1 billion purchase price, reflecting the impact of a $59 million deferred tax liability recorded only at Exelon Corporate to reflect unitary state income tax consequences of the merger.

The excess of the purchase price over the estimated fair value of the assets acquired and the liabilities assumed totaled $4.0 billion, which was recognized as goodwill by PHI and Exelon at the acquisition date, reflecting the value associated with enhancing Exelon's regulated utility portfolio of businesses, including the ability to leverage experience and best practices across the utilities and the opportunities for synergies. For purposes of future required impairment assessments, the goodwill has been preliminarily assigned to PHI's reportable units Pepco, DPL and ACE in the amounts of $1.7 billion, $1.1 billion and $1.2 billion, respectively. None of this goodwill is expected to be tax deductible.

Immediately following closing of the merger, $235 million of net assets included in the table above associated with PHI's unregulated business interests were distributed by PHI to Exelon. Exelon contributed $163 million of such net assets to Generation.

The fair values of PHI's assets and liabilities were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing), discount rates reflecting risk inherent in the future cash flows, future market prices and impacts of utility rate regulation. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired.

Through its wholly owned rate regulated utility subsidiaries, most of PHI's assets and liabilities are subject to cost-of-service rate regulation. Under such regulation, rates charged to customers are established by a regulator to provide for recovery of costs and a fair return on invested capital, or rate base, generally measured at historical cost. In applying the acquisition method of accounting, for regulated assets and liabilities included in rate base or otherwise earning a return (primarily property, plant and equipment and regulatory assets earning a return), no fair value adjustments were recorded as historical cost is viewed as a reasonable proxy for fair value.

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

Fair value adjustments were applied to the historical cost bases of other assets and liabilities subject to rate regulation but not earning a return (including debt instruments and pension and OPEB obligations). In these instances, a corresponding offsetting regulatory asset or liability was also established, as the underlying utility asset and liability amounts are recoverable from or refundable to customers at historical cost (and not at fair value) through the rate setting process. Similar treatment was applied for fair value adjustments to record intangible assets and liabilities, such as for electricity and gas energy supply contracts as further described below. Regulatory assets and liabilities established to offset fair value adjustments are amortized in amounts and over time frames consistent with the realization or settlement of the fair value adjustments, with no impact on reported net income. See Note 5 — Regulatory Matters for additional information regarding the fair value of regulatory assets and liabilities established by Exelon and PHI.

Fair value adjustments were recorded at Exelon and PHI for the difference between the contract price and the market price of electricity and gas energy supply contracts of PHI’s wholly owned rate regulated utility subsidiaries. These adjustments are intangible assets and liabilities classified as unamortized energy contracts on Exelon’s and PHI’s Consolidated Balance Sheets as of June 30, 2017. The difference between the contract price and the market price at the acquisition date of the Merger was recognized for each contract as either an intangible asset or liability. In total, Exelon and PHI recorded a net $1.5 billion liability reflecting out-of-the-money contracts. The valuation of the acquired intangible assets and liabilities was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. In certain instances, the valuations were based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power prices and the discount rate. The unamortized energy contract fair value adjustment amounts and the corresponding offsetting regulatory asset and liability amounts are amortized through Purchase power and fuel expense or Operating revenues, as applicable, over the life of the applicable contract in relation to the present value of the underlying cash flows as of the merger date.

As mentioned, under cost-of-service rate regulation, rates charged to customers are established by a regulator to provide for recovery of costs and a fair return on invested capital, or rate base, generally measured at historical cost. Historical cost information therefore is the most relevant presentation for the financial statements of PHI’s rate regulated utility subsidiary registrants, Pepco, DPL and ACE. As such, Exelon and PHI did not push-down the application of acquisition accounting to PHI’s utility registrants, and therefore the financial statements of Pepco, DPL and ACE do not reflect the revaluation of any assets and liabilities.

The current impact of PHI, including its unregulated businesses, on Exelon’s Consolidated Statements of Operations and Comprehensive Income includes:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Operating revenues	$ 1,113	$ 1,112	$2,332	$1,219
Net income (loss)	61	52	202	(262)

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

For the three and six months ended June 30, 2017 and 2016, the Registrants have recognized costs to achieve the PHI acquisition as follows:

Acquisition, Integration and Financing Costs[(a)]	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Exelon[(b)]	$ 8	$ 1	$ 17	$ 103
Generation	4	4	13	20
ComEd[(c)]	—	1	1	(7)
PECO	1	1	2	2
BGE[(d)]	1	(5)	2	(4)
Pepco[(e)]	1	(4)	2	23
DPL[(f)]	—	—	(7)	16
ACE	1	2	2	15

Acquisition, Integration and Financing Costs[(a)]	*Successor* Three Months Ended June 30, 2017	*Successor* Three Months Ended June 30, 2016	*Successor* Six Months Ended June 30, 2017	*Successor* March 24, 2016 to June 30, 2016	*Predecessor* January 1, 2016 to March 23, 2016
PHI[(g)]	$ 2	$ (1)	$ (2)	$ 55	$ 29

(a) The costs incurred are classified primarily within Operating and maintenance expense in the Registrants' respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the financing costs, which are included within Interest expense. Costs do not include merger commitments discussed above.
(b) Reflects costs (benefits) recorded at Exelon related to financing, including mark-to-market activity on forward-starting interest rate swaps.
(c) For the six months ended June 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million, incurred at ComEd that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 — Regulatory Matters for more information.
(d) For the three and six months ended June 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $6 million incurred at BGE that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 — Regulatory Matters for more information.
(e) For the three and six months ended June 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $9 million incurred at Pepco that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 — Regulatory Matters for more information.
(f) For the six months ended June 30, 2017, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million incurred at DPL that have been deferred and recorded as a regulatory asset for anticipated recovery. For the three and six months ended June 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $3 million incurred at DPL that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 — Regulatory Matters for more information.
(g) For the six months ended June 30, 2017, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million incurred at PHI that have been deferred and recorded as a regulatory asset for anticipated recovery. For the three months ended June 30, 2016 and the Successor period March 24, 2016 to June 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $12 million incurred at PHI that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 — Regulatory Matters for more information.

Pro-forma Impact of the Merger

The following unaudited pro forma financial information reflects the consolidated results of operations of Exelon as if the merger with PHI had taken place on January 1, 2015. The unaudited pro forma information was calculated after applying Exelon's accounting policies and adjusting PHI's results to reflect purchase accounting adjustments.

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

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the merger events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

	Three Months Ended June 30, 2016[(a)]	Six Months Ended June 30, 2016[(a)]	Year Ended December 31, 2016[(b)]
Total operating revenues	$ 6,910	$ 15,466	$ 32,342
Net income attributable to common shareholders	268	845	1,562
Basic earnings per share	$ 0.29	$ 0.92	$ 1.69
Diluted earnings per share	0.29	0.91	1.69

(a) The amounts above include adjustments for non-recurring costs directly related to the merger of $1 million and $641 million for the three and six months ended June 30, 2016, respectively, and intercompany revenue of $170 million for the six months ended June 30, 2016.
(b) The amounts above include adjustments for non-recurring costs directly related to the merger of $680 million and intercompany revenue of $171 million for the year ended December 31, 2016.

Asset Divestitures (Exelon, Generation, PHI and Pepco)

EGTP, a Delaware limited liability company, was formed in 2014 with the purpose of financing a portfolio of assets comprised of two combined-cycle gas turbines (CCGTs) and three peaking/simple cycle facilities consisting of approximately 3.4 GW of generation capacity in ERCOT North and Houston Zones. EGTP is an indirect wholly owned subsidiary of Exelon and Generation. Each of the aforementioned facilities is held through a wholly owned direct subsidiary of EGTP. EGTP also owns two equity method investments in shared facility companies. EGTP, its direct parent and its wholly owned subsidiaries secured a nonrecourse senior secured term loan facility, a revolving loan facility and certain commodity and interest rate swaps.

On May 2, 2017, EGTP entered into a consent agreement with its lenders to permit EGTP to draw on its revolving credit facility and initiate an orderly sales process to sell the assets of its wholly owned subsidiaries, the proceeds from which will first be used to pay the administrative costs of the sale, the normal and ordinary costs of operating the plants and repayment of the secured debt of EGTP, including the revolving credit facility. See Note 10 — Debt and Credit Agreements for details regarding the nonrecourse debt associated with EGTP. As a result, certain EGTP assets and liabilities were classified as held for sale at their respective fair values less costs to sell and included in the other current assets and other current liabilities balances on Exelon's and Generation's Consolidated Balance Sheets. At June 30, 2017, a $418 million pre-tax impairment loss was recorded within Operating and maintenance expense on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. See Note 6 — Impairment of Long-Lived Assets for further information.

On April 21, 2016, Generation completed the sale of the retired New Boston generating site, located in Boston, Massachusetts, resulting in a pre-tax gain of approximately $32 million.

On May 2, 2016, Pepco completed the sale of the New York Avenue land parcel, located in Washington D.C., resulting in a pre-tax gain of approximately $8 million at Pepco. Due to the fair value adjustments recorded at Exelon and PHI as part of purchase accounting, no gain was recorded in the Exelon and PHI Consolidated Statements of Operations and Comprehensive Income.

5. Regulatory Matters (All Registrants)

Except for the matters noted below, the disclosures set forth in Note 3 — Regulatory Matters of the Exelon 2016 Form 10-K reflect, in all material respects, the current status of regulatory and legislative proceedings of the Registrants. The following is an update to that discussion.

Illinois Regulatory Matters

Distribution Formula Rate (Exelon and ComEd). On April 13, 2017, ComEd filed its annual distribution formula rate with the ICC pursuant to EIMA. The filing establishes the revenue requirement used to set the rates that will take effect in January 2018 after the ICC's review and approval, which is due by December 2017. The revenue requirement requested is based on 2016 actual costs plus projected 2017 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2016 to the actual costs incurred that year. ComEd's 2017 filing request includes a total increase to the revenue requirement of $96 million, reflecting an increase of $78 million for the initial revenue requirement for 2017 and an increase of $18 million related to the annual reconciliation for 2016. The revenue requirement for 2017 provides for a weighted average debt and equity return on distribution rate base of 6.47% inclusive of an allowed ROE of 8.40%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2016 provided for a weighted average debt and equity return on distribution rate base of 6.45% inclusive of an allowed ROE of 8.34%, reflecting the average rate on 30-year treasury notes plus 580 basis points less a performance metrics penalty of 6 basis points. See table below for ComEd's regulatory assets associated with its distribution formula rate. For additional information on ComEd's distribution formula rate filings see Note 3 — Regulatory Matters of the Exelon 2016 Form 10-K.

On December 6, 2016, the ICC issued a final order approving the 2016 distribution formula rate, which included a total increase to the revenue requirement of $127 million, reflecting an increase of $134 million for the initial revenue requirement for 2016 and a decrease of $7 million related to the annual reconciliation for 2015. On December 20, 2016, the ICC granted ComEd's and other parties' joint application for rehearing on the impact that changing ComEd's OSHA recordable rate for 2014 and 2015 had on the revenue requirement approved in this order. On March 22, 2017, the ICC issued an order approving ComEd's proposal to reduce the 2016 revenue requirement by $18 million, which was reflected in customer rates in April 2017.

Illinois Future Energy Jobs Act (Exelon, Generation, and ComEd).

Background

On December 7, 2016, FEJA was signed into law by the Governor of Illinois. FEJA was effective June 1, 2017, and includes, among other provisions, (1) a Zero Emission Standard (ZES) providing compensation for certain nuclear-powered generating facilities, (2) an extension of and certain adjustments to ComEd's electric distribution formula rate, (3) new cumulative persisting annual energy efficiency MWh savings goals for ComEd, (4) revisions to the Illinois RPS requirements, (5) provisions for adjustments to or termination of FEJA programs if the average impact on ComEd's customer rates exceeds specified limits, (6) revisions to the existing net metering statute and (7) support for low income rooftop and community solar programs.

Zero Emission Standard

FEJA includes a ZES that provides compensation through the procurement of ZECs targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet specific eligibility criteria.

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

On July 21, 2017, Exelon and others submitted comments on the IPA's draft Procurement Plan. The IPA filed the plan with the ICC on July 31, 2017. The ICC has 45 days to approve the plan. Once the plan is approved by the ICC, bidders interested in participating in the procurement process will have 14 days to submit the required eligibility information and become qualified bidders. Generation's Clinton and Quad Cities nuclear plants will participate in the procurement process. Winning bidders will contract directly with Illinois utilities, including ComEd, for 10-year terms extending through May 31, 2027. The ZEC price will be based upon the current social cost of carbon as determined by the Federal government and is initially established at $16.50 per MWh of production, subject to annual future adjustments determined by the IPA for specified escalation and pricing adjustment mechanisms designed to lower the ZEC price based on increases in underlying energy and capacity prices. Utilities will be required to purchase an amount of ZECs equivalent to 16% of the actual amount of electricity delivered in 2014, subject to specified annual caps. For the initial delivery year, June 1, 2017 — May 31, 2018, the targeted procurement of ZECs, after applying the cap, is set at $235 million (ComEd's share is approximately $170 million). For subsequent delivery years, the IPA-approved targeted ZEC procurement amounts will change based on forward energy and capacity prices

ComEd currently expects to enter into contracts with winning bidders in the fourth quarter 2017, at which time it will begin recording an associated obligation and expense for the procurement of ZEC's. Winning bidders will be entitled to compensation for the sale of ZECs retroactive to the June 1, 2017 effective date of FEJA.

ComEd will recover all costs associated with purchasing ZECs through a new rate rider that provides for an annual reconciliation and true-up to actual costs incurred by ComEd to purchase ZECs, with any difference to be credited to or collected from ComEd's retail customers in subsequent periods with interest. ComEd began billing its retail customers under its new ZEC rate rider on June 1, 2017 and recorded a regulatory liability of $22 million as of June 30, 2017 for revenues recorded in advance of incurring expenses.

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. One lawsuit was filed by customers of ComEd, led by the Village of Old Mill Creek, and the other was brought by the EPSA and three other electric suppliers. Both lawsuits argue that the Illinois ZEC program will distort PJM's FERC-approved energy and capacity market auction system of setting wholesale prices, and seek a permanent injunction preventing the implementation of the program. Exelon intervened and filed motions to dismiss in both lawsuits. In addition, on March 31, 2017, plaintiffs in both lawsuits filed motions for preliminary injunction with the court; the court stayed briefing on the motions for preliminary injunction until the resolution of the motions to dismiss. On July 14, 2017, the court granted the motions to dismiss and also dismissed the motions for preliminary injunction. On July 17, 2017, the plaintiffs appealed the court's decisions to the U.S. Court of Appeals for the Seventh Circuit. Exelon cannot predict the outcome of these lawsuits. It is possible that resolution of these matters could have a material, unfavorable impact on Exelon's and Generation's results of operations, financial positions and cash flows.

See Note 7 — Early Nuclear Plant Retirements for additional information regarding the economic challenges facing Generation's Clinton and Quad Cities nuclear plants and the expected benefits of the ZES.

ComEd Electric Distribution Rates

FEJA extends the sunset date for ComEd's performance-based electric distribution formula rate from 2019 to the end of 2022, allows ComEd to revise the electric distribution formula rate to eliminate the ROE collar, and allows ComEd to implement a decoupling tariff if the electric distribution formula rate is terminated at any time. ComEd will revise its electric distribution formula rate to eliminate the ROE collar beginning with the reconciliation filed in 2018 for the 2017 calendar year. Elimination of the ROE collar effectively offsets the favorable or unfavorable impacts to Operating revenues associated with variations in delivery volumes associated with above or below normal weather, numbers of customers or usage per customer. ComEd began reflecting the impacts of this change in its electric distribution services costs regulatory asset in first quarter 2017. As of June 30, 2017, ComEd recorded an increase to Operating revenues and its electric distribution services costs regulatory asset of approximately $36 million for this change.

FEJA requires ComEd to make non-recoverable contributions to low income energy assistance programs of $10 million per year for 5 years as long as the electric distribution formula rate remains in effect. With the exception of these contributions, ComEd will recover from customers, subject to certain caps explained below, the costs it incurs pursuant to FEJA either through its electric distribution formula rate or other recovery mechanisms.

Energy Efficiency

Prior to FEJA, Illinois law required ComEd to implement cost-effective energy efficiency measures and, for a 10-year period ending May 31, 2018, cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers.

Beginning January 1, 2018, FEJA provides for new cumulative annual energy efficiency MWh savings goals for ComEd, which are designed to achieve 21.5% of cumulative persisting annual MWh savings by 2030, as compared to the deemed baseline of 88 million MWhs of electric power and energy sales. FEJA deems the cumulative persisting annual MWh savings to be 6.6% from 2012 through the end of 2017. ComEd expects to spend approximately $250 million to $400 million annually from 2017 through 2030 to achieve these energy efficiency MWh savings goals. In addition, FEJA extends the peak demand reduction requirement from 2018 to 2026. Because the new requirements apply beginning in 2018, FEJA extends the existing energy efficiency plans, which were due to end on May 31, 2017, through December 31, 2017. FEJA also exempts customers with demands over 10 MW from energy efficiency plans and requirements beginning June 1, 2017. On June 30, 2017, ComEd filed its 2018 — 2021 energy efficiency plan with the ICC, which must be approved no later than September 14, 2017.

FEJA allows ComEd to cancel its existing energy efficiency rate rider and replace it with an energy efficiency formula rate, and to defer energy efficiency costs (except for any voltage optimization costs which will be recovered through the electric distribution formula rate) as a separate regulatory asset that will be recovered through the energy efficiency formula rate over the weighted average useful life, as approved by the ICC, of the related energy efficiency measures. ComEd will earn a return on the energy efficiency regulatory asset at a rate equal to its weighted average cost of capital, which is based on a year-end capital structure and calculated using the same methodology applicable to ComEd's electric distribution formula rate. Beginning January 1, 2018 through December 31, 2030, the return on equity that ComEd earns on its energy efficiency regulatory asset is subject to a maximum downward or upward adjustment of 200 basis points if ComEd's cumulative persisting annual MWh savings falls short of or exceeds specified percentage benchmarks of its annual incremental savings goal. ComEd will be required to file an update to its energy efficiency formula rate on or before June 1 each year, with resulting rates effective in January of the following year. The annual update will be based on projected current year energy efficiency costs, PJM capacity revenues, and the projected year-end regulatory asset balance less any related deferred income taxes. The update will also include a reconciliation of any differences between the revenue requirement in effect for the prior year and the revenue requirement based on actual prior year costs and actual year-end energy efficiency regulatory asset balances less any related deferred income taxes. ComEd will record a regulatory asset or liability and corresponding increase or decrease to Operating revenues for any differences between the revenue requirement in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation.

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

ComEd cancelled its existing energy efficiency rate rider effective June 2, 2017. ComEd will perform a reconciliation of revenues and costs incurred through the cancellation date and issue a one-time credit on retail customers' bills for any over-recoveries. As of June 30, 2017, ComEd's over-recoveries associated with its former energy efficiency rate rider were $88 million, which were reflected in Current regulatory liabilities on Exelon's and ComEd's Consolidated Balance Sheets as ComEd expects to provide the one-time credit to customers within the next twelve months.

Initial Energy Efficiency Formula Rate Filing

On June 9, 2017, ComEd filed its new initial energy efficiency formula rate with the ICC pursuant to FEJA. The filing establishes the formula under which energy efficiency rates will be calculated going forward and the revenue requirement used to set the initial rates for the period October 1, 2017 through December 31, 2017 subject to the ICC's review and approval, which is required by August 23, 2017. The initial revenue requirement is based on projected costs and projected PJM capacity revenues for the period from June 1, 2017 through December 31, 2017, and projected year-end 2017 energy efficiency regulatory asset balances (less any related deferred income taxes). ComEd requested an initial decrease in revenue requirement of $7 million reflecting higher projected PJM capacity revenues compared to projected energy efficiency costs and provides for a weighted average debt and equity return of 6.47% inclusive of an allowed ROE of 8.40%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2017 will be included in ComEd's 2018 energy efficiency formula rate filing and reflected in customer rates beginning January 2019. As of June 30, 2017, under the new formula rate, Exelon and ComEd deferred $21 million of energy efficiency costs as a regulatory asset. ComEd also recorded a regulatory liability of $2 million for the 2017 energy efficiency formula rate annual reconciliation.

2017 Energy Efficiency Formula Rate Filing

On June 30, 2017, ComEd filed its annual energy efficiency formula rate with the ICC pursuant to FEJA. The filing establishes the revenue requirement used to set rates that will take effect in January 2018 after the ICC's review and approval, which is due no later than September 14, 2017. The revenue requirement for 2018 is based on projected 2018 energy efficiency costs and PJM capacity revenues, and year-end 2018 energy efficiency regulatory asset balances (less any related deferred income taxes). In its 2017 filing ComEd requested a total increase to the revenue requirement of $12 million and provides for a weighted average debt and equity return of 6.47% inclusive of an allowed ROE of 8.40%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2018 will be included in ComEd's 2019 energy efficiency formula rate filing, and reflected in customer rates beginning January 2020.

Renewable Portfolio Standard

Existing Illinois law requires ComEd to purchase each year an increasing percentage of renewable energy resources for the customers for which it supplies electricity. This obligation is satisfied through the procurement of RECs. FEJA revises the Illinois RPS to require ComEd to procure RECs for all retail customers by June 2019, regardless of the customers' electricity supplier, and provides support for low-income rooftop and community solar programs, which will be funded by the existing Renewable Energy Resources Fund and ongoing RPS collections. FEJA also requires ComEd to use RPS collections to fund utility job training and workforce development programs in the amounts of $10 million in each of the years 2017, 2021, and 2025. ComEd recorded a $10 million and $20 million current and non-current liability, respectively, as of June 30, 2017 associated with this obligation. ComEd will recover all costs associated with purchasing RECs and funding utility job training and workforce development programs through a new RPS rate rider that provides for a reconciliation and true-up to actual costs, with any difference between revenues and expenses to be credited to or collected from ComEd's retail customers in subsequent periods with interest. The first reconciliation and true-up for RECs will occur in 2021 and cover revenues and costs for the four year period beginning June 1, 2017 through May 31, 2021. Subsequently, the RPS rate rider will provide for an annual reconciliation and true-up. ComEd began billing its retail customers under its new RPS rate rider on June 1, 2017 and recorded a related regulatory asset of $19 million as of June 30, 2017. Any over-recovered RPS costs will be deposited into a separate interest bearing bank account pursuant to FEJA, which will be classified as Restricted cash on Exelon's and ComEd's Consolidated Balance Sheets.

Customer Rate Increase Limitations

FEJA includes provisions intended to limit the average impact on ComEd customer rates for recovery of costs incurred under FEJA as follows: (1) for a typical ComEd residential customer, the average impact must be less than $0.25 cents per month, (2) for nonresidential customers with a peak demand less than 10 MW, the average annual impact must be less than 1.3% of the average amount paid per kWh for electric service by Illinois commercial retail customers during 2015, and (3) for nonresidential customers with a peak demand greater than 10 MW, the average annual impact must be less than 1.3% of the average amount paid per kWh for electric service by Illinois industrial retail customers during 2015.

On June 30, 2017, ComEd submitted a 10-year projection to the ICC of customer rate impacts for residential customers and nonresidential customers with a peak demand less than 10 MW. Such projections indicate that customer rate impacts will not exceed the limitations set by FEJA discussed below. Thereafter, beginning in 2018, ComEd must submit a report to the ICC for residential customers and nonresidential customers with a peak demand less than 10 MW by February 15th and June 30th of each year, respectively. For nonresidential customers with a peak demand greater than 10 MW, ComEd must submit a report to the ICC by May 1 of each year if a rate reduction will be necessary in the following year. For residential customers, the reports will include the actual costs incurred under FEJA during the preceding year and a rolling 10-year customer rate impact projection. The reports for nonresidential customers with a peak demand less than 10 MW will also include the actual costs incurred under FEJA during the preceding year, as well as the average annual rate increase from January 1, 2017 through the end of the preceding year and the average annual rate increase projected for the remainder of the 10-year period.

If the projected residential customer or nonresidential customer with a peak demand less than 10 MW rate increase exceeds the limitations during the first four years, ComEd is required to decrease costs associated with FEJA investments, including reductions to ZEC contract quantities. If the projected residential customer or nonresidential customer with a peak demand less than 10 MW rate increase exceeds the limitations during the last six years, ComEd is required to demonstrate how it will reduce FEJA investments to ensure compliance. If the actual residential customer or nonresidential customer with a peak demand less than 10 MW rate increase exceeds the limitations for any one year, ComEd is required to submit a corrective action plan to decrease future year costs to reduce customer rates to ensure future compliance. If the actual residential customer or nonresidential customer rate exceeds the limitations for two consecutive years, ComEd can offer to credit customers for amounts billed in excess of the limitations or ComEd can terminate FEJA investments. If ComEd chooses to terminate FEJA investments, the ICC shall order termination of ZEC contracts and further initiate proceedings to reduce energy efficiency savings goals and terminate support for low-income rooftop and community solar programs. ComEd is allowed to fully recover all costs incurred as of and up to the date of the programs' termination.

For the energy efficiency formula, ComEd records a regulatory asset or liability and corresponding increase or decrease to Operating revenues for any differences between the revenue requirement in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation. For the other rate riders be established under FEJA, ComEd records a regulatory asset or liability for any differences between revenues and incurred expenses.

Renewable Energy Resources (Exelon and ComEd). In accordance with legislation in effect on December 31, 2016, the IPA's Procurement Plans include the procurement of cost-effective renewable energy resources in amounts that equal or exceed a minimum target percentage of the total electricity that each electric utility supplies to its eligible retail customers. The June 1, 2016 target renewable energy resources obligation for the utilities was at least 11.5%. This obligation increases by at least 1.5% each year thereafter to an ultimate target of at least 25% by June 1, 2025. All goals are subject to rate impact criteria set forth by Illinois legislation. As of June 30, 2017, ComEd had purchased renewable energy resources or equivalents, such as RECs, in accordance with the IPA Procurement Plan. ComEd currently retires all RECs upon transfer and acceptance. ComEd is permitted to recover procurement costs of RECs from retail customers without mark-up through rates.

In accordance with FEJA that took effect on June 1, 2017, beginning with the plan or plans to be implemented in the 2017 delivery year, the IPA shall develop a long term renewable resources procurement plan (LT Plan). The RPS target percentages for the overall service territory have not changed through June 1, 2025 although FEJA extended the 25% RPS target to delivery years after 2025. Currently, each RES and each utility is responsible for the renewable resource obligation of the customers it supplies power for. Over time, this will change and the utility will procure renewable resources based on the retail load of substantially all customers in its service territory. For the delivery year beginning June 1, 2017, the LT Plan shall include cost effective renewable energy resources procured by the utility for the retail load the utility supplies and for 50% of the retail customer load supplied by Retail Electric Suppliers in the utility service territory on February 28, 2017. Utility procurement for RES supplied retail customer load will increase to 75% June 1, 2018 and to 100% beginning June 1, 2019.

Pennsylvania Regulatory Matters

Pennsylvania Procurement Proceedings (Exelon and PECO). Through PECO's PAPUC approved DSP Programs, PECO procures electric supply for its default electric customers through PAPUC approved competitive procurements.

On March 17, 2016, PECO filed its fourth DSP Program with the PAPUC proposing a 24-month term from June 1, 2017 through May 31, 2019, in compliance with electric generation procurement guidelines set forth in Act 129. On December 8, 2016, the PAPUC approved the fourth DSP Program for the modified 48-month term and deferred CAP Shopping to another proceeding. OCA and Low Income Advocates subsequently filed a Petition for Reconsideration and Clarification related to CAP Shopping. On March 16, 2017, the PAPUC granted reconsideration and consolidated the proceeding with the DSP II docket, which includes the pending CAP Shopping plan that would allow low-income CAP customers to purchase their generation supply from EGSs. PAPUC referred the consolidated proceedings to the Office of Administrative Law Judge for hearing and decision.

Pennsylvania Act 11 of 2012 (Exelon and PECO). In February 2012, Act 11 was signed into law, which provided the PAPUC authority to approve the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities' aging electric and natural gas distribution systems in Pennsylvania. Prior to recovering costs pursuant to a DSIC, the PAPUC's implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIP) approved by the Commission, which outlines how the utility is planning to increase its investment for repairing, improving or replacing aging infrastructure. The PAPUC approved PECO's petition for its proposed electric DSIC and LTIIP on October 22, 2015 for spending of $275 million over a 5 year period through 2020. The

PAPUC approved PECO's petition for its proposed modified gas LTIIP on June 14, 2017 for spending of $762 million over a 10 year period through 2022.

Maryland Regulatory Matters

2017 Maryland Electric Distribution Rates (Exelon, PHI and Pepco). On March 24, 2017, Pepco filed an application with the MDPSC requesting an increase of $69 million based on a ROE of 10.1%. The application includes a request for an income tax adjustment to reflect full normalization of removal costs associated with pre-1981 property, which accounts for $18 million of the requested increase. Pepco expects a decision in the matter in the fourth quarter of 2017, but cannot predict how much of the requested rate increase the MDPSC will approve or if it will approve the requested income tax adjustment.

2017 Maryland Electric Distribution Rates (Exelon, PHI and DPL). On July 14, 2017, DPL filed an application with the MDPSC to increase its annual electric distribution base rates by $27 million based on a requested ROE of 10.1%. DPL expects a decision on the matter in the first quarter of 2018. DPL cannot predict how much of the requested increase the MDPSC will approve.

2016 Maryland Electric Distribution Rates (Exelon, PHI and DPL). On February 15, 2017, the MDPSC approved an increase in DPL electric distribution rates of $38 million based on a ROE of 9.6%. The new rates became effective for services rendered on or after February 15, 2017. The MDPSC also denied DPL's request to continue its Grid Resiliency Program, through which DPL proposed to invest $4.6 million a year for two years to improve priority feeders and install single-phase reclosing fuse technology. The final order did not result in the recognition of any incremental regulatory assets or liabilities.

Cash Working Capital Order (Exelon and BGE). On November 17, 2016, the MDPSC rendered a decision in the proceeding to review BGE's request to recover its cash working capital (CWC) requirement for its Provider of Last Resort service, also known as Standard Offer Service (SOS), as well as other components that make up the Administrative Charge, the mechanism that enables BGE to recover all of its SOS-related costs. The Administrative Charge is now comprised of five components: CWC, uncollectibles, incremental costs, return, and an administrative adjustment, which is an adder to the utility's SOS rate to act as a proxy for retail suppliers' costs. The Commission accepted BGE's positions on recovery of CWC and pass-through recovery of BGE's actual uncollectibles and incremental costs. The order also grants BGE a return on the SOS. The Commission ruled that the level of the administrative adjustment will be determined in BGE's next rate case. On December 16, 2016, MDPSC Staff requested clarification concerning the amount of return on the SOS awarded to BGE and on December 19, 2016, the residential consumer advocate sought rehearing of the return awarded. On January 24, 2017, the MDPSC issued an order denying the MDPSC Staff request for clarification and the residential consumer advocate request for rehearing. On February 22, 2017, the residential consumer advocate filed an appeal of the MDPSC's orders with the Circuit Court for Baltimore City. The residential consumer advocate filed its Memorandum on Appeal on June 5, 2017 and subsequent Reply Memoranda were filed by BGE and the MDPSC on July 7, 2017 and July 12, 2017, respectively. Oral arguments are scheduled for August 7, 2017. BGE cannot predict the outcome of this appeal.

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that included the planned installation of 2 million residential and commercial electric and natural gas smart meters at an expected total cost of $480 million of which $200 million was funded by SGIG. The MDPSC's approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. As of June 30, 2017 and December 31, 2016, the balance of BGE's regulatory asset was $225 million and $230 million, respectively, representing incremental program deployment costs. The current quarter balance of $225 million consists of three major components, including $137 million of unamortized incremental deployment costs of the AMI program, $56 million of unamortized costs of the non-AMI meters replaced under the program, and $32 million related to post-test year incremental program deployment costs incurred prior to approval became effective June 2016. The balance as of June 30, 2017 reflects the impact of the cost disallowances and adjustments in BGE's 2015 electric and natural gas distribution rate case. The incremental deployment costs for the AMI program and the non-AMI meter components of the regulatory asset are being recovered through rates and amortized to expense over a 10 year period, while the post-test year incremental program deployment costs have not yet been approved for recovery by the MDPSC. A return on the regulatory asset is currently included in rates, except for the $56 million portion representing the unamortized cost of the retired non-AMI meters and a $32 million portion related to post-test year incremental program deployment costs.

As a combined result of the MDPSC orders in BGE's 2015 electric and natural gas distribution rate case, BGE recorded a $52 million charge in June 2016 to Operating and maintenance expense in Exelon's and BGE's Consolidated Statements of Operations and Comprehensive Income reducing certain regulatory assets and other long-lived assets and reclassified $56 million of non-AMI plant costs from Property, plant and equipment, net to Regulatory assets on Exelon's and BGE's Consolidated Balance Sheets. For further information, see Note 3 —Regulatory Matters of the Exelon 2016 Form 10-K.

Delaware Regulatory Matters

Gas Cost Rates (Exelon, PHI and DPL). DPL makes an annual GCR filing with the DPSC for the purpose of allowing DPL to recover natural gas procurement costs through customer rates. In August 2016, DPL made its 2016-2017 GCR filing. The rates proposed in the 2016-2017 GCR filing resulted in a GCR increase of approximately 14%. On September 20, 2016, the DPSC issued an order allowing DPL to place the new rates into effect on November 1, 2016, subject to refund and pending final DPSC approval. A settlement agreement was reached by all parties. On April 20, 2017, the DPSC issued an order which approved the settlement agreement and made the rates approved as final effective November 1, 2016.

2016 Electric and Natural Gas Distribution Rates (Exelon, PHI and DPL). On May 17, 2016, DPL filed an application with the DPSC to increase its annual electric and natural gas distribution base rates by $63 million (which was updated to $60 million on March 8, 2017) and $22 million, respectively, based on a requested ROE of 10.6%. Delaware law allowed DPL to put into effect $2.5 million of each of the rate increases effective July 16, 2016. On December 17, 2016, the DPSC approved an additional $29.6 million in electric distribution rates and an additional $10.4 million in natural gas distribution rates effective December 17, 2016, subject to refund based on the final DPSC orders.

On March 8, 2017, DPL entered into a settlement agreement with the Division of the Public Advocate, Delaware Electric Users Group and the DPSC Staff in its electric distribution rate proceeding, which provides for an increase in DPL annual electric distribution base rates of $31.5 million based on an ROE of 9.7% compared to the $32.1 million increase previously put into effect. On May 23, 2017, the DPSC issued an order approving the settlement agreement, with the new rates effective June 1, 2017. Pursuant to the settlement agreement, no refund of the interim rates put into effect on July 16, 2016 and December 17, 2016 (as discussed above) is required.

On April 6, 2017, DPL entered into a settlement agreement with the Division of the Public Advocate and the DPSC Staff in its natural gas distribution rate proceeding, which provides for an increase in DPL annual natural gas distribution base rates of $4.9 million based on an ROE of 9.7%. The settlement agreement also provides that DPL will refund amounts collected under the temporary rates effective July 16, 2016 and December 17, 2016 (as discussed above) in excess of the $4.9 million, and that the new rates will be effective within thirty days of DPSC approval of the settlement agreement. On June 6, 2017, the DPSC issued an order approving the settlement agreement, with the new rates effective July 1, 2017. Pursuant to the settlement agreement, a rate refund plus interest of approximately $5 million will be issued to customers beginning in August 2017 for which a regulatory liability has been recorded as of June 30, 2017.

District of Columbia Regulatory Matters

2016 Electric Distribution Rates (Exelon, PHI and Pepco). On June 30, 2016, Pepco filed an application with the DCPSC to increase its annual electric distribution base rates by $86 million, as updated to approximately $77 million on February 1, 2017, based on a requested ROE of 10.6%.

On July 25, 2017, the DCPSC issued an order granting Pepco an increase to its annual electric distribution base rates of $36.9 million based on an ROE of 9.5%. The new rates will be effective August 15, 2017. In its decision, the DCPSC ordered that the $25.6 million customer rate credit created as a result of the Exelon and PHI merger will be provided primarily to residential customers and some small commercial customers to offset the impact of this increase until that amount has been exhausted, which is expected to take approximately two years. Additionally, the Commission is holding approximately $6 million to $7 million of the customer rate credit for use toward a possible new class of customers for certain senior citizens and disabled persons. The DCPSC also held that Pepco's bill stabilization adjustment, which decouples distribution revenues from utility customers from the amount of electricity delivered, will continue to be in place and that no refund of previously collected funds is required. Parties have 30 days from the date of the order to file for reconsideration with the DCPSC.

District of Columbia Power Line Undergrounding Initiative (Exelon, PHI and Pepco). The District of Columbia government enacted on an emergency basis (effective May 17, 2017) and thereafter on a permanent basis (effective July 11, 2017) legislation to amend the Electric Company Infrastructure Improvement Financing Act of 2014 (as amended) (the Infrastructure Improvement Financing Act) to authorize the District of Columbia Power Line Undergrounding (DC PLUG) initiative, a projected six year, $500 million project to place underground some of the District of Columbia's most outage-prone power lines with $250 million of the project costs funded by Pepco and $250 million funded by the District of Columbia.

The $250 million of project costs funded by Pepco will be recovered through a volumetric surcharge on the electric bill of substantially all of Pepco's customers in the District of Columbia. Pepco will earn a return on these project costs.

The $250 million of project costs funded by the District of Columbia will come from two sources. Project costs of $187.5 million will be funded through a charge assessed on Pepco by the District of Columbia; Pepco will recover this charge from customers through a volumetric distribution rider. The remaining costs up to $62.5 million are to be funded by the existing capital projects program of the District Department of Transportation (DDOT). Ownership and responsibility for the operation and maintenance of all the assets funded by the District of Columbia will be transferred to Pepco for a nominal amount upon completion. Pepco will not recover or earn a return on the cost of the assets transferred to it by the District of Columbia.

In accordance with the Infrastructure Improvement Financing Act, Pepco filed an application for approval of the first two-year portion of the DC PLUG initiative (the First Biennial Plan) on July 3, 2017. After the initial application, Pepco will be required to make two updated applications, one every two years until the project is completed. Pepco anticipates that the DCPSC will issue an order approving the First Biennial Plan in the fourth quarter of 2017. Upon the issuance of a DCPSC order approving the First Biennial Plan, Pepco will become obligated to pay $187.5 million to the District of Columbia over the six year project term, at which time it will record an obligation and offsetting regulatory asset.

New Jersey Regulatory Matters

2017 Electric Distribution Rates (Exelon, PHI and ACE). On March 30, 2017, ACE submitted an application with the NJBPU to increase its electric distribution rates by approximately $70 million (before New Jersey sales and use tax), which was updated to $72.6 million on July 14, 2017, based upon a requested ROE of 10.1%. The application also requests approval of a rate surcharge mechanism called the “System Renewal Recovery Charge,” which would permit more timely recovery of certain costs associated with reliability and system renewal-related capital investments. ACE currently expects a decision in this matter in the first quarter of 2018, but cannot predict how much of the requested increase the NJBPU will approve.

2016 Electric Distribution Rates (Exelon, PHI and ACE). On August 24, 2016, the NJBPU issued an order approving a stipulation of settlement among ACE, the New Jersey Division of Rate Counsel, NJBPU Staff and Unimin Corporation, which, among other things, provided that a determination on ACE’s grid resiliency program, PowerAhead, would be separated into a phase II of the rate proceeding and decided at a later date. PowerAhead includes capital investments to enhance the resiliency of the system through improvements focused on improving the distribution system’s ability to withstand major storm events. A stipulation of settlement with respect to the PowerAhead program (the PowerAhead Stipulation) was approved by the NJBPU on May 31, 2017. As adopted, the PowerAhead program includes an approved investment level of $79 million to be recovered through the cost recovery mechanism described in the PowerAhead Stipulation. The NJBPU order adopting the PowerAhead Stipulation was effective on June 10, 2017.

Update and Reconciliation of Certain Under-Recovered Balances (Exelon, PHI and ACE). On February 1, 2017, ACE submitted its 2017 annual petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE’s long-term power purchase contracts with the non-utility generators and (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and ACE’s uncollectible accounts. As filed, the net impact of adjusting the charges as proposed would have been an overall annual rate decrease of approximately $29 million (revised to approximately $32 million in April 2017, based upon an update for actuals through March 2017), including New Jersey sales and use tax. On May 31, 2017, the NJBPU approved a stipulation of settlement entered into by the parties providing for an overall annual rate decrease of approximately $32 million, effective June 1, 2017. The rate decrease was placed into effect provisionally, subject to a review by NJBPU and the Division of Rate Counsel of the final underlying costs for reasonableness and prudence. This rate decrease will have no effect on ACE’s operating income, since these revenues provide for recovery of deferred costs under an approved deferral mechanism. The matter is pending at the NJBPU.

New York Regulatory Matters

New York Clean Energy Standard (Exelon, Generation). On August 1, 2016, the New York Public Service Commission (NYPSC) issued an order establishing the CES, a component of which is the 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. The New York State Energy Research and Development Authority (NYSERDA) will centrally procure the ZECs from eligible plants through a 12-year contract, to be administered in six two-year tranches, extending from April 1, 2017 through March 31, 2029. ZEC payments will be made to the eligible resources based upon the number of MWh produced, subject to specified caps and minimum performance requirements. The price to be paid for the ZECs under each tranche will be administratively determined using a formula based on the social cost of carbon as determined in 2016 by the federal government, subject to pricing adjustments designed to lower the ZEC price based on increase in underlying energy and capacity prices. The ZEC price for the first tranche has been set at $17.48 per

MWh of production. Following the first tranche, the price will be updated bi-annually. Each Load Serving Entity (LSE) shall be required to purchase an amount of ZECs equivalent to its load ratio share of the total electric energy in the New York Control Area. Cost recovery from ratepayers shall be incorporated into the commodity charges on customer bills.

The NYPSC initially identified three plants eligible for the ZEC program: the FitzPatrick, Ginna, and Nine Mile Point nuclear facilities. As issued, the order also provided that the duration of the program beyond the first tranche was conditional upon a buyer purchasing the FitzPatrick facility and taking title prior to September 1, 2018. On November 18, 2016, the required contracts with NYSERDA were executed for Ginna and Nine Mile Point, in addition to Entergy's execution of the required contract for the FitzPatrick facility. On March 31, 2017, Generation closed on the acquisition of FitzPatrick. Generation is currently recognizing revenue for the sale of New York ZECs in the month following generation when the ZECs are transferred to NYSERDA. For the three months ended June 30, 2017 Generation has recognized $73 million of ZEC revenue.

Several parties filed with the NYPSC requests for rehearing or reconsideration of the CES. Generation and CENG also filed a request for clarification, or in the alternative limited rehearing, that the condition limiting the duration of the program beyond the first tranche be limited to the eligibility of the FitzPatrick plant only and have no bearing on Ginna or Nine Mile Point's eligibility for the full 12-year duration. On December 15, 2016, the NYPSC approved Generation's and CENG's petition to clarify this condition and denied all petitions for rehearing of the CES. Parties had until mid-April to appeal to New York State court the denials of the requests for rehearing. A Petition seeking to invalidate the ZEC program was filed in New York State court by certain environmental groups and other parties on November 30, 2016, and amended on January 13, 2017, arguing that the NYPSC violated certain technical provisions of the State Administrative Procedures Act (SAPA) when adopting the ZEC program. On February 15, 2017, Generation and CENG filed a motion to dismiss the state court action. The NYPSC also filed a motion to dismiss the state court action. On March 24, 2017, the plaintiffs filed a memorandum of law opposing the motions to dismiss, and Generation and CENG filed a reply brief on April 28, 2017. Oral argument was held on June 19, 2017. The motion is pending.

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. On December 9, 2016, Generation and CENG filed a motion to intervene in the case and to dismiss the lawsuit. The State also filed a motion to dismiss. Briefing has been completed on the motion to dismiss, and oral argument was held on March 29, 2017. The motion to intervene has been granted. On July 25, 2017, the court granted both motions to dismiss. Plaintiffs are expected to appeal.

Other legal challenges remain possible, the outcomes of which remain uncertain. See Note 7 — Early Nuclear Plant Retirements for additional information relative to Ginna and Nine Mile Point. See Note 4 —Mergers, Acquisitions and Dispositions for additional information on Generation's acquisition of FitzPatrick.

Ginna Nuclear Power Plant Reliability Support Services Agreement (Exelon and Generation). In November 2014, in response to a petition filed by Ginna Nuclear Power Plant (Ginna) regarding the possible retirement of Ginna, the NYPSC directed Ginna and Rochester Gas & Electric Company (RG&E) to negotiate a Reliability Support Services Agreement (RSSA) to support the continued operation of Ginna to maintain the reliability of the RG&E transmission grid for a specified period of time. During 2015 and 2016, Ginna and RG&E made filings with the NYPSC and FERC for their approval of the proposed RSSA. Although the RSSA was still subject to regulatory approvals, on April 1, 2015, Ginna began delivering the power and capacity from the Ginna plant into the ISO-NY consistent with the technical provisions of the RSSA.

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

On March 22, 2016, Ginna submitted a compliance filing with FERC with revisions to the RSSA requested by FERC. On April 8, 2016, FERC accepted the compliance filing and on April 20, 2016, the NYPSC accepted the revised RSSA with a term expiring on March 31, 2017. In April 2016, Generation began recognizing revenue based on the final approved pricing contained in the RSSA and also recognized a one-time revenue adjustment of approximately $101 million representing the net cumulative previously unrecognized amount of revenue retroactive from the April 1, 2015 effective date through March 31, 2016. A 49.99% portion of the one-time adjustment was removed from Generation's results of operations as a result of the noncontrolling interests in CENG.

The RSSA required Ginna to continue operating through the RSSA term. On September 30, 2016, Ginna filed the required notice with the NYPSC of its intent to continue operating beyond the March 31, 2017 expiry of the RSSA, conditioned upon successful execution of an agreement between Ginna and NYSERDA for the sale of ZECs under the CES. As stated previously, on November 18, 2016 the required contract with NYSERDA was executed by Generation and CENG for Ginna. Upon the expiry of the RSSA on March 31, 2017, Ginna was required to make refund payments of $20 million to RG&E related to capital expenditures. Ginna paid RGE the $20 million in June 2017. Additionally, the provisions of the RSSA provided for a one-time payment of $12 million to be paid from RGE to Ginna at the end of the contract. This $12 million was recognized in revenue as of March 31, 2017. RGE paid the $12 million to Ginna in May 2017. Subject to prevailing over any administrative or legal challenges, it is expected the CES will allow Ginna to continue to operate through the end of its current operating license in 2029. See Note 7-Early Nuclear Plant Retirements for further information regarding the impacts of a decision to early retire one or more nuclear plants.

Federal Regulatory Matters

Transmission Formula Rate (Exelon, ComEd, BGE, Pepco, DPL and ACE). The following total increases/(decreases) were included in ComEd's, BGE's, Pepco's, DPL's and ACE's electric transmission formula rate filings:

	2017				
Annual Transmission Filings[(a)]	ComEd	BGE	Pepco	DPL	ACE
Initial revenue requirement increase	$ 44	$ 31	$ 5	$ 6	$ 20
Annual reconciliation (decrease) increase	(33)	3	15	8	22
Dedicated facilities decrease [(b)]	—	(8)	—	—	—
Total revenue requirement increase	$ 11	$ 26	$ 20	$ 14	$ 42
Allowed return on rate base [(c)]	8.43%	7.47%	7.92%	7.16%	8.02%
Allowed ROE [(d)]	11.50%	10.50%	10.50%	10.50%	10.50%

(a) All rates are effective June 2017, subject to review by the FERC and other parties, which is due by fourth quarter 2017.
(b) BGE's transmission revenues include a FERC approved dedicated facilities charge to recover the costs of providing transmission service to specifically designated load by BGE.
(c) Represents the weighted average debt and equity return on transmission rate bases.
(d) As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.50% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%. As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL and ACE, the rate of return on common equity is 10.50%, inclusive of a 50 basis point incentive adder for being a member of a regional transmission organization.

For additional information regarding transmission formula rate filings see Note 3 — Regulatory Matters of the Exelon 2016 Form 10-K.

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 would 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. PECO cannot predict the final outcome of the settlement or hearing proceedings, or the transmission formula FERC may approve.

PJM Transmission Rate Design and Operating Agreements (Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO, BGE, Pepco, DPL and ACE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. In April 2007, FERC issued an order concluding that PJM's current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. A number of parties appealed to the U.S. Court of Appeals for the Seventh Circuit for review of the decision.

In August 2009, the court issued its decision affirming the FERC's order with regard to the existing facilities, but remanded to FERC the issue of the cost allocation associated with the new facilities 500 kV and above (Cost Allocation Issue) for further consideration by the FERC. On remand, FERC reaffirmed its earlier decision to socialize the costs of new facilities 500 kV and above. A number of parties filed appeals of these orders. In June 2014, the court again remanded the Cost Allocation Issue to FERC. On December 18, 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the Cost Allocation Issue. On June 15, 2016, a number of parties, including Exelon and the Utility Registrants, filed a proposed Settlement with FERC. If the Settlement is approved, 50% of the costs of the 500 kV and above facilities approved by the PJM Board on or before February 1, 2013 will be socialized across PJM and 50% will be allocated according to a formula that calculates the flows on the transmission facilities. Each state that is a party in this proceeding either signed, or did not oppose, the settlement. The Settlement is opposed by a number of merchant transmission owners and New York load-serving entities. The Settlement includes provisions for monthly credits or charges that are expected to be mostly refunded or recovered through customer rates over a 10-year period based on negotiated numbers for charges prior to January 1, 2016.

Exelon expects that the Settlement will not have a material impact on the results of operations, cash flows and financial position of Generation, ComEd, PECO, BGE, Pepco, DPL or ACE. The Settlement is subject to approval by FERC.

Complaints at FERC Seeking to Mitigate Illinois and New York Programs Providing ZECs (Exelon and Generation). 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 remove the revenues it receives through a federal, state or other 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 resources. Exelon has generally opposed policies that require subsidies or give preferential treatment to generation providers or technologies that do not provide superior reliability or environmental benefits, or that would threaten the reliability and value of the integrated electricity grid. Thus, Exelon has supported a MOPR as a means of minimizing the detrimental impact certain subsidized resources could have on capacity markets (such as the New Jersey (LCAPP) and Maryland (CfD) programs). However, in Exelon's view, MOPRs should not be applied to resources that receive compensation for providing superior reliability or environmental benefits.

On January 9, 2017, the Electric Power Supply Association (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. Both filings allege that the relevant MOPR should be expanded to also apply to existing resources receiving ZEC compensation under the New York CES and Illinois ZES programs. Exelon has 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 that have generally not been subject to a MOPR. However, if successful, for Generation's facilities in NYISO and PJM expected to receive ZEC compensation (Quad Cities, Ginna, Nine Mile Point and FitzPatrick), 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 those auctions and thus no longer receiving capacity revenues during the respective ZEC programs. Any such mitigation of these generating resources could have a material effect on Exelon's and Generation's future cash flows and results of operations. The timing of FERC's decision with respect to both proceedings is currently unknown and the outcome of these matters is currently uncertain.

Operating License Renewals (Exelon and Generation). On August 29, 2012, Generation submitted a hydroelectric license application to FERC for a 46-year 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 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. In addition, Generation continues to work with MDE and other Federal and Maryland state agencies to conduct and fund an additional sediment and nutrient monitoring study.

On April 21, 2016, Exelon and Interior executed a Settlement Agreement resolving all fish passage issues between the parties. The financial impact of the Settlement Agreement is estimated to be $3 million to $7 million per year, on average, over the 46-year life of the new license, including both capital and operating costs. The actual timing and amount of these costs are not currently fixed and may vary significantly from year to year throughout the life of the new license. Resolution of the remaining issues relating to Conowingo involving various stakeholders may have a material effect on Exelon's and Generation's results of operations and financial position through an increase in capital expenditures and operating costs. As of June 30, 2017, $29 million of direct costs associated with Conowingo licensing efforts have been capitalized. See Note 3 — Regulatory Matters of the Exelon 2016 Form 10-K for additional information on Generation's operating license renewal efforts.

Regulatory Assets and Liabilities (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE each prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

As a result of applying the acquisition method of accounting and pushing it down to the consolidated financial statements of PHI, certain regulatory assets and liabilities were established at Exelon and PHI to offset the impacts of fair valuing the acquired assets and liabilities assumed which are subject to regulatory recovery. In total, Exelon and PHI recorded a net $2.4 billion regulatory asset reflecting adjustments recorded as a result of the acquisition method of accounting. See Note 4 — Mergers, Acquisitions and Dispositions for additional information.

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

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE as of June 30, 2017 and December 31, 2016. For additional information on the specific regulatory assets and liabilities, refer to Note 3 — Regulatory Matters of the Exelon 2016 Form 10-K.

June 30, 2017	Exelon	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Regulatory assets								
Pension and other postretirement benefits [a]	$ 4,086	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes [b]	2,091	76	1,645	100	270	176	41	53
AMI programs	679	163	43	225	248	167	81	—
Under-recovered distribution service costs [c]	239	239	—	—	—	—	—	—
Energy efficiency costs	19	19	—	—	—	—	—	—
Debt costs	117	39	1	7	77	16	8	6
Fair value of long-term debt	782	—	—	—	645	—	—	—
Fair value of PHI's unamortized energy contracts	918	—	—	—	918	—	—	—
Severance	3	—	—	3	—	—	—	—
Asset retirement obligations	119	84	23	12	—	—	—	—
MGP remediation costs	289	266	23	—	—	—	—	—
Under-recovered uncollectible accounts	55	55	—	—	—	—	—	—
Renewable energy	258	256	—	—	2	—	1	1
Energy and transmission programs [d][e][f][g][h][i]	69	8	1	21	39	6	6	27
Deferred storm costs	34	—	—	—	34	10	6	18
Electric generation-related regulatory asset	5	—	—	5	—	—	—	—
Energy efficiency and demand response programs	590	—	1	271	318	236	82	—
Merger integration costs [j][k]	32	—	—	7	25	12	13	—
Under-recovered revenue decoupling [l]	74	—	—	35	39	31	8	—
COPCO acquisition adjustment	6	—	—	—	6	—	6	—
Workers compensation and long-term disability cost	34	—	—	—	34	34	—	—
Vacation accrual	47	—	22	—	25	—	15	10
Securitized stranded costs	108	—	—	—	108	—	—	108
CAP arrearage	10	—	10	—	—	—	—	—
Removal costs	500	—	—	—	500	138	95	268
Renewable portfolio standards costs	19	19	—	—	—	—	—	—
Other	55	8	9	6	32	21	8	4
Total regulatory assets	11,238	1,232	1,778	692	3,320	847	370	495
Less: current portion	1,293	182	46	197	605	165	71	89
Total non-current regulatory assets	$ 9,945	$1,050	$1,732	$495	$ 2,715	$682	$299	$406

June 30, 2017	Exelon	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Regulatory liabilities								
Other postretirement benefits	$ 43	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Nuclear decommissioning	2,870	2,364	506	—	—	—	—	—
Removal costs	1,592	1,332	—	129	131	18	113	—
Deferred rent	38	—	—	—	38	—	—	—
Energy efficiency and demand response programs	128	88	39	—	1	1	—	—
DLC program costs	8	—	8	—	—	—	—	—
Electric distribution tax repairs	59	—	59	—	—	—	—	—
Gas distribution tax repairs	16	—	16	—	—	—	—	—
Energy and transmission programs [d][e][f][g][h][i]	123	40	61	—	22	2	12	8
Rate stabilization deferral	3	—	—	3	—	—	—	—
Zero emission credit costs	22	22	—	—	—	—	—	—
Other	70	8	10	25	27	1	13	12
Total regulatory liabilities	4,972	3,854	699	157	219	22	138	20
Less: current portion	574	269	155	67	68	5	43	20
Total non-current regulatory liabilities	$ 4,398	$3,585	$ 544	$ 90	$ 151	$ 17	$ 95	$ —

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

December 31, 2016	Exelon	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
Regulatory assets								
Pension and other postretirement benefits [(a)]	$ 4,162	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes [(b)]	2,016	75	1,583	98	260	171	38	51
AMI programs	701	164	49	230	258	174	84	—
Under-recovered distribution service costs [(c)]	188	188	—	—	—	—	—	—
Debt costs	124	42	1	7	81	17	9	6
Fair value of long-term debt	812	—	—	—	671	—	—	—
Fair value of PHI's unamortized energy contracts	1,085	—	—	—	1,085	—	—	—
Severance	5	—	—	5	—	—	—	—
Asset retirement obligations	111	76	23	12	—	—	—	—
MGP remediation costs	305	278	26	1	—	—	—	—
Under-recovered uncollectible accounts	56	56	—	—	—	—	—	—
Renewable energy	260	258	—	—	2	—	—	2
Energy and transmission programs [(d)(e)(f)(g)(h)(i)]	89	23	—	38	28	6	5	17
Deferred storm costs	36	—	—	1	35	12	5	18
Electric generation-related regulatory asset	10	—	—	10	—	—	—	—
Rate stabilization deferral	7	—	—	7	—	—	—	—
Energy efficiency and demand response programs	621	—	1	285	335	250	85	—
Merger integration costs [(j)(k)]	25	—	—	10	15	11	4	—
Under-recovered revenue decoupling [(l)]	27	—	—	3	24	21	3	—
COPCO acquisition adjustment	8	—	—	—	8	—	8	—
Workers compensation and long-term disability costs	34	—	—	—	34	34	—	—
Vacation accrual	31	—	7	—	24	—	14	10
Securitized stranded costs	138	—	—	—	138	—	—	138
CAP arrearage	11	—	11	—	—	—	—	—
Removal costs	477	—	—	—	477	134	88	255
Other	49	7	9	5	29	22	5	4
Total regulatory assets	11,388	1,167	1,710	712	3,504	852	348	501
Less: current portion	1,342	190	29	208	653	162	59	96
Total non-current regulatory assets	$10,046	$ 977	$1,681	$504	$ 2,851	$690	$289	$405

December 31, 2016	Exelon	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
Regulatory liabilities								
Other postretirement benefits	$ 47	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Nuclear decommissioning	2,607	2,169	438	—	—	—	—	—
Removal costs	1,601	1,324	—	141	136	18	118	—
Deferred rent	39	—	—	—	39	—	—	—
Energy efficiency and demand response programs	185	141	41	—	3	3	—	—
DLC program costs	8	—	8	—	—	—	—	—
Electric distribution tax repairs	76	—	76	—	—	—	—	—
Gas distribution tax repairs	20	—	20	—	—	—	—	—
Energy and transmission programs [(d)(e)(f)(g)(h)(i)]	134	60	56	—	18	8	5	5
Other	72	4	5	19	41	2	17	20
Total regulatory liabilities	4,789	3,698	644	160	237	31	140	25
Less: current portion	602	329	127	50	79	11	43	25
Total non-current regulatory liabilities	$ 4,187	$3,369	$ 517	$110	$ 158	$ 20	$ 97	$ —

(a) As of June 30, 2017 and December 31, 2016, the pension and other postretirement benefits regulatory asset at Exelon includes regulatory assets of $1,025 million and $995 million, respectively, as a result of the PHI Merger related to unrecognized costs that are probable of regulatory recovery. The regulatory assets are amortized over periods from 3 to 15 years, depending on the underlying component. Pepco, DPL and ACE are currently recovering these costs through base rates. Pepco, DPL and ACE are not earning a return on the recovery of these costs in base rates.

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

(b) As of June 30, 2017, includes transmission-related regulatory assets that require FERC approval separate from the transmission formula rate of $22 million, $41 million, $33 million, $22 million and $20 million for ComEd, BGE, Pepco, DPL and ACE, respectively. As of December 31, 2016, includes transmission-related regulatory assets that require FERC approval separate from the transmission formula rate of $22 million, $38 million, $31 million, $20 million and $19 million for ComEd, BGE, Pepco, DPL and ACE, respectively. On December 13, 2016, BGE filed with FERC to begin recovering these existing and any similar future regulatory assets through its transmission formula rate. On May 9, 2017, FERC accepted BGE's filing and made effective BGE's proposed modifications to its transmission formula rate, subject to refund and further Commission order. ComEd, Pepco, DPL, and ACE are expected to make similar filings with FERC and other parties in subsequent periods.

(c) As of June 30, 2017, ComEd's regulatory asset of $239 million was comprised of $184 million for the 2015 — 2017 annual reconciliations and $55 million related to significant one-time events including $14 million of deferred storm costs, $9 million of Constellation and PHI merger and integration related costs, $3 million of emerald ash borer costs, and $29 million of smart meter related costs. As of December 31, 2016, ComEd's regulatory asset of $188 million was comprised of $134 million for the 2015 and 2016 annual reconciliations and $54 million related to significant one-time events, including $20 million of deferred storm costs and $11 million of Constellation and PHI merger and integration related costs, and $23 million of smart meter related costs. See Note 4 — Merger, Acquisitions, and Dispositions of the Exelon 2016 Form 10-K for further information.

(d) As of June 30, 2017, ComEd's regulatory asset of $8 million reflects Constellation merger and integration costs to be recovered upon FERC approval. As of June 30, 2017, ComEd's regulatory liability of $40 million included $8 million related to over-recovered energy costs and $32 million associated with revenues received for renewable energy requirements. As of December 31, 2016, ComEd's regulatory asset of $23 million included $15 million associated with transmission costs recoverable through its FERC approved formula rate and $8 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2016, ComEd's regulatory liability of $60 million included $30 million related to over-recovered energy costs and $30 million associated with revenues received for renewable energy requirements.

(e) As of June 30, 2017, PECO's regulatory asset of $1 million related to under-recovered electric transmission costs. As of June 30, 2017, PECO's regulatory liability of $61 million included $36 million related to over-recovered costs under the DSP program, $16 million related to the over-recovered natural gas costs under the PGC and $9 million related to over-recovered non-bypassable transmission service charges. As of December 31, 2016, PECO's regulatory liability of $56 million included $34 million related to over-recovered costs under the DSP program, $10 million related to over-recovered non-bypassable transmission service charges, $8 million related to the over-recovered natural gas costs under the PGC and $4 million related to the over-recovered electric transmission costs.

(f) As of June 30, 2017, BGE's regulatory asset of $21 million included $10 million related to under-recovered electric energy costs, $5 million related to under-recovered natural gas costs, $4 million of costs associated with transmission costs recoverable through its FERC approved formula rate and $2 million of abandonment costs to be recovered upon FERC approval. As of December 31, 2016, BGE's regulatory asset of $38 million included $4 million of costs associated with transmission costs recoverable through its FERC approved formula rate, $28 million related to under-recovered electric energy costs, $3 million of abandonment costs to be recovered upon FERC approval, and $3 million of under-recovered natural gas costs.

(g) As of June 30, 2017, Pepco's regulatory asset of $6 million included $2 million of transmission costs recoverable through its FERC approved formula rate and $4 million of under-recovered electric energy costs. As of June 30, 2017, Pepco's regulatory liability of $2 million related to over-recovered electric energy costs. As of December 31, 2016, Pepco's regulatory asset of $6 million related to under-recovered electric energy costs. As of December 31, 2016, Pepco's regulatory liability of $8 million included $5 million of over-recovered transmission costs and $3 million of over-recovered electric energy costs.

(h) As of June 30, 2017, DPL's regulatory asset of $6 million related to under-recovered electric energy costs. As of June 30, 2017, DPL's regulatory liability of $12 million included $10 million of over-recovered electric energy costs and $2 million of over-recovered gas cost. As of December 31, 2016, DPL's regulatory asset of $5 million included $1 million of transmission costs recoverable through its FERC approved formula rate and $4 million of under-recovered electric energy costs. As of December 31, 2016, DPL's regulatory liability of $5 million included $2 million of over-recovered electric energy costs and $3 million of over-recovered transmission costs.

(i) As of June 30, 2017, ACE's regulatory asset of $27 million included $11 million of transmission costs recoverable through its FERC approved formula rate and $16 million of under-recovered electric energy costs. As of June 30, 2017, ACE's regulatory liability of $8 million related to over-recovered electric energy costs. As of December 31, 2016, ACE's regulatory asset of $17 million included $6 million of transmission costs recoverable through its FERC approved formula rate and $11 million of under-recovered electric energy costs. As of December 31, 2016, ACE's regulatory liability of $5 million included $4 million of over-recovered transmission costs and $1 million of over-recovered electric energy costs.

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(j) As of June 30, 2017 and December 31, 2016, BGE's regulatory asset of $7 million and $10 million, respectively, included $6 million of previously incurred PHI acquisition costs as authorized by the June 2016 rate case order.

(k) As of June 30, 2017 and December 31, 2016, Pepco's regulatory asset of $12 million and $11 million, respectively, represents previously incurred PHI acquisition costs authorized for recovery by the November 2016 Maryland distribution rate case order. As of June 30, 2017, DPL's regulatory asset of $13 million represents previously incurred PHI acquisition costs, including $4 million authorized for recovery by the February 2017 Maryland distribution rate case order, $6 million authorized for recovery by the May 2017 Delaware electric distribution rate case order, and $3 million expected to be recovered in electric and gas distribution rates in the Delaware service territory. As of December 31, 2016, DPL's regulatory asset of $4 million represents previously incurred PHI acquisition costs expected to be recovered in distribution rates in the Maryland service territory.

(l) Represents the electric and natural gas distribution costs recoverable from customers under BGE's decoupling mechanism. As of June 30, 2017, BGE had a regulatory asset of $24 million related to under-recovered electric revenue decoupling and $11 million related to under-recovered natural gas revenue decoupling. As of December 31, 2016, BGE had a regulatory asset of $2 million related to under-recovered natural gas revenue decoupling and $1 million related to under-recovered electric revenue decoupling.

Capitalized Ratemaking Amounts Not Recognized (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

The following table illustrates our authorized amounts capitalized for ratemaking purposes related to earnings on shareholders' investment that are not recognized for financial reporting purposes on our Consolidated Balance Sheets. These amounts will be recognized as revenues in our 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
June 30, 2017	$ 71	$ 6	$ —	$ 55	$10	$ 6	$ 4	$—

	Exelon	ComEd[(a)]	PECO	BGE[(b)]	PHI	Pepco[(c)]	DPL[(c)]	ACE
December 31, 2016	$ 72	$ 5	$ —	$ 57	$10	$ 6	$ 4	$—

(a) Reflects ComEd's unrecognized equity returns earned for ratemaking purposes on its under-recovered distribution services costs regulatory assets.
(b) BGE's authorized amounts capitalized for ratemaking purposes 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.

Purchase of Receivables Programs (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

ComEd, PECO, BGE, Pepco, DPL and ACE are required, under separate legislation and regulations in Illinois, Pennsylvania, Maryland, District of Columbia and New Jersey, to purchase certain receivables from retail electric and 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 is required to purchase receivables at face value and is permitted to recover uncollectible accounts expense, including those from Third Party Suppliers, from customers through distribution rates. ACE purchases receivables at face value. ACE recovers all uncollectible accounts expense, including those from Third

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Party Suppliers, through the Societal Benefits Charge (SBC) rider, which includes uncollectible accounts expense as a component. The SBC is filed annually with the NJBPU. Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE do not record unbilled commodity receivables under the POR programs. Purchased billed receivables are classified in Other accounts receivable, net on Exelon's, ComEd's, PECO's, BGE's, PHI's, Pepco's, DPL's and ACE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of those companies as of June 30, 2017 and December 31, 2016.

As of June 30, 2017	Exelon	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
Purchased receivables[b]	$ 304	$ 85	$ 73	$ 53	$ 93	$ 61	$10	$ 22
Allowance for uncollectible accounts[a]	(31)	(12)	(5)	(3)	(11)	(6)	(2)	(3)
Purchased receivables, net	$ 273	$ 73	$ 68	$ 50	$ 82	$ 55	$ 8	$ 19

As of December 31, 2016	Exelon	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
Purchased receivables[b]	$ 313	$ 87	$ 72	$ 59	$ 95	$ 63	$10	$ 22
Allowance for uncollectible accounts[a]	(37)	(14)	(6)	(4)	(13)	(7)	(2)	(4)
Purchased receivables, net	$ 276	$ 73	$ 66	$ 55	$ 82	$ 56	$ 8	$ 18

(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 its Purchase of Receivables with Consolidated Billing tariff.

(b) Pepco's electric POR program in Maryland included a discount on purchased receivables ranging from 0% to 2% depending on customer class. Pepco's electric POR program in the District of Columbia included a discount on purchased receivables ranging from 0% to 6% through April 6, 2017 and 0% to 2% effective April 7, 2017, depending on customer class. DPL's electric POR program in Maryland included a discount on purchased receivables ranging from 0% to 1% through May 31, 2017 and 0% to 4% effective June 1, 2017, depending on customer class.

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

Long-Lived Assets (Exelon and Generation)

Generation evaluates long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. EGTP's operating cash flows have been negatively impacted by certain market conditions and the seasonality of its cash flows. On May 2, 2017, EGTP entered into a consent agreement with its lenders to initiate an orderly sales process to sell the assets of its wholly owned subsidiaries, the proceeds from which will first be used to pay the administrative costs of the sale, the normal and ordinary costs of operating the plants and repayment of the secured debt of EGTP. As a result, certain EGTP's assets and liabilities were classified as held for sale at their respective fair values less costs to sell and included in the other current assets and other current liabilities balances on Exelon's and Generation's Consolidated Balance Sheets at June 30, 2017. Additionally, a pre-tax impairment charge of $418 million was recorded in June 2017 within Operating and maintenance expense on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. See Note 4 — Mergers, Acquisitions and Dispositions for additional information.

During the first quarter of 2016, significant changes in Generation's intended use of the Upstream oil and gas assets, developments with nonrecourse debt held by its upstream subsidiary CEU Holdings, LLC (as described in Note 14 — Debt and Credit Agreements of the Exelon 2016 Form 10-K) and continued declines in both production volumes and commodity prices suggested that the carrying value may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of its Upstream properties were less than their carrying values. As a result, a pre-tax impairment charge of $119 million was recorded in March 2016 within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. On June 16, 2016, Generation initiated the sales process of its Upstream business by executing a forbearance agreement with the lenders of the nonrecourse debt. An additional pre-tax impairment charge of $15 million was recorded in September 2016 within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income due to further declines in fair value. In December 2016, Generation sold substantially all of the Upstream Assets. See Note 4 — Mergers, Acquisitions and Dispositions of the Exelon 2016 Form 10-K for further information.

In the second quarter of 2016, updates to the Company's long-term view of energy and capacity prices suggested that the carrying value of a group of merchant wind assets, located in West Texas, may be impaired. Upon review, the estimated undiscounted future cash flows and fair value of the group were less than their carrying value. The fair value analysis was based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As a result of the fair value analysis, long-lived assets held and used with a carrying amount of approximately $60 million were written down to their fair value of $24 million and a pre-tax impairment charge of $36 million was recorded during the second quarter in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Also in the second quarter of 2016, updates to the Company's long-term view, as described above, in conjunction with the previous decision to early retire the Clinton and Quad Cities nuclear facilities in Illinois suggested that the carrying value of our Midwest asset group may be impaired. Generation completed a comprehensive review of the estimated undiscounted future cash flows of the Midwest asset group and no impairment charge was required.

Like-Kind Exchange Transaction (Exelon)

In June 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon Corporation, entered into transactions pursuant to which UII invested in coal-fired generating station leases (Headleases) with the Municipal Electric Authority of Georgia (MEAG). The generating stations were leased back to MEAG as part of the transactions (Leases).

On March 31, 2016, UII and MEAG finalized an agreement to terminate the MEAG Headleases, the MEAG Leases, and other related agreements prior to their expiration dates. As a result of the lease termination, UII received an early termination payment of $360 million from MEAG and wrote-off the $356 million net investment in the MEAG Headleases and the Leases. The transaction resulted in a pre-tax gain of $4 million which is reflected in Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income. See Note 11 — Income Taxes for additional information.

7. Early Nuclear Plant Retirements (Exelon and Generation)

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation's nuclear plants. Factors that will continue to affect the economic value of Generation's nuclear plants include, but are not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions to ensure nuclear plants are fairly compensated for their carbon-free emissions, 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 nuclear plant, and the resulting financial statement impacts, may be affected by a number of 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 decommissioning trust fund requirements, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity or other obligations, where applicable, and just prior to its next scheduled nuclear refueling outage.

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In 2015 and 2016, Generation identified the Clinton, Quad Cities, Ginna, Nine Mile Point, and Three Mile Island (TMI) nuclear plants as having the greatest risk of early retirement based on economic valuation and other factors. PSEG has also recently made public similar financial challenges facing its New Jersey nuclear plants including Salem, of which Generation owns a 42.59% ownership interest. As previously disclosed, Exelon and Generation have committed to cease operation of the Oyster Creek nuclear plant by the end of 2019.

The TMI nuclear plant did not clear in the May 2017 PJM capacity auction for the 2020-2021 planning year and will not receive capacity revenue for that period, the third consecutive year that TMI failed to clear the PJM base residual capacity auction. The plant is currently committed to operate through May 2019.

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. The current NRC license for TMI expires in 2034. Generation is proceeding with the market and regulatory notifications that must be made to shut down the plant, including filing of a deactivation notice with PJM on May 30, 2017 and notification to the NRC on June 20, 2017. PJM has subsequently notified Generation that it has not identified any reliability issues and has approved the deactivation of TMI as proposed.

In the second quarter of 2017, as a result of the plant retirement decision of TMI, Exelon and Generation recognized one-time charges in Operating and maintenance expense of $71 million related to materials and supplies inventory reserve adjustments, employee-related costs and construction work-in-progress (CWIP) impairments, among other items. In addition to these one-time charges, there will be ongoing annual incremental non-cash charges to earnings stemming from shortening the expected economic useful life of TMI primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and additional ARO accretion expense associated with the changes in decommissioning timing and cost assumptions. Exelon's and Generation's second quarter 2017 results include an incremental $37 million of pre-tax expense for these items. Please refer to Note 12 — Nuclear Decommissioning for additional detail on changes to the nuclear decommissioning ARO balances resulting from the early retirement of TMI.

Income statement expense (pre-tax)	June 30, 2017
Depreciation and amortization	
Accelerated depreciation[(a)]	$ 35
Accelerated Nuclear Fuel amortization	2
Total	$ 37

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

Based on insufficient capacity auction results and the lack of progress on Illinois energy legislation, on June 2, 2016, Generation announced a decision to shut down the Clinton and Quad Cities nuclear plants on June 1, 2017 and June 1, 2018, respectively. With the passage of the Illinois ZES on December 7, 2016, and subject to prevailing over any related administrative or legal challenges, Generation reversed this decision and revised the expected economic useful lives for both facilities; 2027 for Clinton and 2032 for Quad Cities. Refer to Note 5 — Regulatory Matters for additional discussion on the Illinois ZES.

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Exelon's and Generation's 2016 results included a net incremental $714 million of total pre-tax expense associated with the initial early retirement decision for Clinton and Quad Cities, as summarized in the table below.

Income statement expense (pre-tax)	Q2 2016	Q3 2016	Q4 2016	YTD 2016
Depreciation and amortization				
Accelerated depreciation[a]	$115	$344	$ 253	$712
Accelerated Nuclear Fuel amortization	9	28	23	60
Operating and maintenance				
One time charges[b]	141	5	(120)	26
ARO accretion, net of contractual offset[c]	—	2	—	2
Contractual offset for ARC depreciation[c]	(14)	(41)	(31)	(86)
Total	$251	$338	$ 125	$714

(a) Reflects incremental accelerated depreciation of plant assets, including any ARC, for the period June 2, 2016, through December 6, 2016.
(b) Primarily includes materials and supplies inventory reserve adjustments, employee related costs and construction work-in-progress (CWIP) impairments.
(c) For Quad Cities based on the regulatory agreement with the Illinois Commerce Commission, decommissioning-related activities are offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset results in an equal adjustment to the noncurrent payables to ComEd at Generation and an adjustment to the regulatory liabilities at ComEd. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability.

In New York, the Ginna, Nine Mile Point, and Generation's recently acquired FitzPatrick nuclear plant also faced significant economic challenges and risk of retirement before the end of each unit's respective operating license period (2029 for Ginna and Nine Mile Point Unit 1, 2046 for Nine Mile Point Unit 2, and 2034 for FitzPatrick). On August 1, 2016, the NYPSC issued an order adopting the CES that, subject to prevailing over any administrative or legal challenges, would allow Ginna, Nine Mile Point, and FitzPatrick to continue to operate at least through the life of the program (March 31, 2029). The assumed useful life for depreciation purposes for each facility is through the end of their current operating licenses. Ginna most recently operated under an RSSA which expired March 31, 2017 and has filed the required notice with the NYPSC of its intent to continue operating beyond the expiry of the RSSA. Refer to Note 4 — Mergers, Acquisitions and Dispositions for additional information on Generation's acquisition of FitzPatrick and Note 5 — Regulatory Matters for additional discussion on the Ginna RSSA and the New York CES.

Assuming the successful implementation of the Illinois ZES and the New York CES and the continued effectiveness of these programs, Generation and CENG, through its ownership of Ginna and Nine Mile Point, no longer consider Clinton, Quad Cities, Ginna or Nine Mile Point to be at heightened risk for early retirement. However, to the extent either the Illinois ZES or the New York CES programs do not operate as expected over their full terms, each of these plants (and now including the newly acquired FitzPatrick) could again be at heightened risk for early retirement, which could have a material impact on Exelon's and Generation's future results of operations, cash flows and financial position.

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

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

Fair Value of Financial Liabilities Recorded at the Carrying Amount

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 June 30, 2017 and December 31, 2016:

Exelon

	June 30, 2017				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 1,757	$ —	$ 1,757	$ —	$ 1,757
Long-term debt (including amounts due within one year)[a]	33,934	—	33,460	1,956	35,416
Long-term debt to financing trusts[b]	641	—	—	693	693
SNF obligation	1,139	—	830	—	830

	December 31, 2016				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 1,267	$ —	$ 1,267	$ —	$ 1,267
Long-term debt (including amounts due within one year)[a]	34,005	1,113	31,741	1,959	34,813
Long-term debt to financing trusts[b]	641	—	—	667	667
SNF obligation	1,024	—	732	—	732

Generation

	June 30, 2017				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 716	$ —	$ 716	$ —	$ 716
Long-term debt (including amounts due within one year)[a]	9,754	—	8,061	1,661	9,722
SNF obligation	1,139	—	830	—	830

	December 31, 2016				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 699	$ —	$ 699	$ —	$ 699
Long-term debt (including amounts due within one year)[a]	9,241	—	7,482	1,670	9,152
SNF obligation	1,024	—	732	—	732

ComEd

	June 30, 2017				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 389	$ —	$ 389	$ —	$ 389
Long-term debt (including amounts due within one year)[a]	7,036	—	7,728	—	7,728
Long-term debt to financing trusts[b]	205	—	—	223	223

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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	December 31, 2016				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 7,033	$ —	$7,585	$ —	$7,585
Long-term debt to financing trusts[b]	205	—	—	215	215

PECO

	June 30, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 2,580	$ —	$2,834	$ —	$2,834
Long-term debt to financing trusts	184	—	—	199	199

	December 31, 2016				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 2,580	$ —	$2,794	$ —	$2,794
Long-term debt to financing trusts	184	—	—	192	192

BGE

	June 30, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 85	$ —	$ 85	$ —	$ 85
Long-term debt (including amounts due within one year)[a]	2,282	—	2,497	—	2,497
Long-term debt to financing trusts[b]	252	—	—	271	271

	December 31, 2016				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 45	$ —	$ 45	$ —	$ 45
Long-term debt (including amounts due within one year)[a]	2,322	—	2,467	—	2,467
Long-term debt to financing trusts[b]	252	—	—	260	260

PHI (Successor)

	June 30, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 67	$ —	$ 67	$ —	$ 67
Long-term debt (including amounts due within one year)[a]	5,952	—	5,707	295	6,002

	December 31, 2016				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 522	$ —	$ 522	$ —	$ 522
Long-term debt (including amounts due within one year)[a]	5,898	—	5,520	289	5,809

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

Pepco

	June 30, 2017				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 2,545	$ —	$3,065	$ 9	$3,074

	December 31, 2016				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 23	$ —	$ 23	$ —	$ 23
Long-term debt (including amounts due within one year)[a]	2,349	—	2,788	8	2,796

DPL

	June 30, 2017				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 25	$ —	$ 25	$ —	$ 25
Long-term debt (including amounts due within one year)[a]	1,326	—	1,398	—	1,398

	December 31, 2016				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 1,340	$ —	$1,383	$ —	$1,383

ACE

	June 30, 2017				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 42	$ —	$ 42	$ —	$ 42
Long-term debt (including amounts due within one year)[a]	1,138	—	980	286	1,266

	December 31, 2016				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 1,155	$ —	$1,007	$ 280	$1,287

(a) Includes unamortized debt issuance costs which are not fair valued of $185 million, $53 million, $44 million, $15 million, $14 million, $6 million, $33 million, $11 million, and $5 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, as of June 30, 2017. Includes unamortized debt issuance costs of $200 million, $64 million, $46 million, $15 million, $15 million, $2 million, $30 million, $11 million, and $6 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, as of December 31, 2016.

(b) Includes unamortized debt issuance costs which are not fair valued of $7 million, $1 million, and $6 million for Exelon, ComEd and BGE, respectively, as of June 30, 2017 and December 31, 2016.

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of dividends payable (included in other current liabilities) (Level 1) and short-term borrowings (Level 2). The Registrants' carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments.

Long-Term Debt. The fair value amounts of Exelon's taxable debt securities (Level 2) and private placement taxable debt securities (Level 3) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the utility sector with similar credit ratings in both the primary and secondary market, across the Registrants' debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note. Due to low trading volume of private placement debt, qualitative factors such as market conditions, low volume of investors and investor demand, this debt is classified as Level 3. The fair value of Exelon's equity units (Level 1) are valued based on publicly traded securities issued by Exelon.

The fair value of Generation's and Pepco's non-government-backed fixed rate nonrecourse debt (Level 3) is based on market and quoted prices for its own and other nonrecourse debt with similar risk profiles. Given the low trading volume in the nonrecourse debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project (e.g., political and regulatory environment). The fair value of Generation's government-backed fixed rate project financing debt (Level 3) is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate financing debt resets on a monthly or quarterly basis and the carrying value approximates fair value (Level 2). When trading data is available on variable rate financing debt, the fair value is based on market and quoted prices for its own and other nonrecourse debt with similar risk profiles (Level 2). Generation, Pepco, DPL and ACE also have tax-exempt debt (Level 2). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (e.g., conduit issuer political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above. Variable rate tax-exempt debt (Level 2) resets on a regular basis and the carrying value approximates fair value.

SNF Obligation. The carrying amount of Generation's SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2030. This amount also includes $110 million as of June 30, 2017 for the fair value of the one-time fee obligation associated with closing of the FitzPatrick acquisition on March 31, 2017. The fair value was determined using a similar methodology, however the New York Power Authority's (NYPA) discount rate is used in place of Generation's given the contractual right to reimbursement from NYPA for the obligation; see Note 4 — Mergers, Acquisitions and Dispositions for additional information on Generation's acquisition of FitzPatrick.

Long-Term Debt to Financing Trusts. Exelon's long-term debt to financing trusts is valued based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities, qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.

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.

Transfers in and out of levels are recognized as of the end of the reporting period when the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Additionally, there were no material transfers between Level 1 and Level 2 during the six months ended June 30, 2017 for cash equivalents, nuclear decommissioning trust fund investments, pledged assets for Zion Station decommissioning, Rabbi trust investments, and deferred compensation obligations. For derivative contracts, transfers into Level 2 from Level 3 generally occur when the contract tenor becomes more observable and due to changes in market liquidity or assumptions for certain commodity contracts.

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.

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

The following tables present assets and liabilities measured and recorded at fair value on Exelon's and Generation's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2017 and December 31, 2016:

	Generation					Exelon				
As of June 30, 2017	**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)]	$ 29	$ —	$ —	$ —	$ 29	$ 257	$ —	$ —	$ —	$ 257
NDT fund investments										
Cash equivalents[(b)]	117	67	—	—	184	117	67	—	—	184
Equities	3,980	717	—	2,104	6,801	3,980	717	—	2,104	6,801
Fixed income										
Corporate debt	—	1,656	255	—	1,911	—	1,656	255	—	1,911
U.S. Treasury and agencies	1,767	32	—	—	1,799	1,767	32	—	—	1,799
Foreign governments	—	51	—	—	51	—	51	—	—	51
State and municipal debt	—	232	—	—	232	—	232	—	—	232
Other[(c)]	—	46	—	502	548	—	46	—	502	548
Fixed income subtotal	1,767	2,017	255	502	4,541	1,767	2,017	255	502	4,541
Middle market lending	—	—	428	78	506	—	—	428	78	506
Private equity	—	—	—	197	197	—	—	—	197	197
Real estate	—	—	—	441	441	—	—	—	441	441
NDT fund investments subtotal[(d)]	5,864	2,801	683	3,322	12,670	5,864	2,801	683	3,322	12,670
Pledged assets for Zion Station decommissioning										
Cash equivalents	21	—	—	—	21	21	—	—	—	21
Middle market lending	—	—	21	33	54	—	—	21	33	54
Pledged assets for Zion Station decommissioning subtotal[(e)]	21	—	21	33	75	21	—	21	33	75
Rabbi trust investments										
Cash equivalents	5	—	—	—	5	78	—	—	—	78
Mutual funds	22	—	—	—	22	54	—	—	—	54
Fixed income	—	—	—	—	—	—	13	—	—	13
Life insurance contracts	—	20	—	—	20	—	67	21	—	88
Rabbi trust investments subtotal	27	20	—	—	47	132	80	21	—	233
Commodity derivative assets										
Economic hedges	632	2,698	1,604	—	4,934	632	2,698	1,604	—	4,934
Proprietary trading	3	47	31	—	81	3	47	31	—	81
Effect of netting and allocation of collateral[(f) (g)]	(627)	(2,343)	(767)	—	(3,737)	(627)	(2,343)	(767)	—	(3,737)
Commodity derivative assets subtotal	8	402	868	—	1,278	8	402	868	—	1,278
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments	—	—	—	—	—	—	11	—	—	11
Economic hedges	—	17	—	—	17	—	17	—	—	17
Proprietary trading	3	1	—	—	4	3	1	—	—	4
Effect of netting and allocation of collateral	(3)	(10)	—	—	(13)	(3)	(10)	—	—	(13)
Interest rate and foreign currency derivative assets subtotal	—	8	—	—	8	—	19	—	—	19
Other investments	—	—	41	—	41	—	—	41	—	41
Total assets	5,949	3,231	1,613	3,355	14,148	6,282	3,302	1,634	3,355	14,573

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

As of June 30, 2017	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	(697)	(2,691)	(1,151)	—	(4,539)	(697)	(2,691)	(1,407)	—	(4,795)
Proprietary trading	(4)	(48)	(25)	—	(77)	(4)	(48)	(25)	—	(77)
Effect of netting and allocation of collateral[f] [g]	698	2,627	897	—	4,222	698	2,627	897	—	4,222
Commodity derivative liabilities subtotal	(3)	(112)	(279)	—	(394)	(3)	(112)	(535)	—	(650)
Interest rate and foreign currency derivative liabilities										
Economic hedges	—	(20)	—	—	(20)	—	(20)	—	—	(20)
Proprietary trading	(4)	—	—	—	(4)	(4)	—	—	—	(4)
Effect of netting and allocation of collateral	3	10	—	—	13	3	10	—	—	13
Interest rate and foreign currency derivative liabilities subtotal	(1)	(10)	—	—	(11)	(1)	(10)	—	—	(11)
Deferred compensation obligation	—	(33)	—	—	(33)	—	(131)	—	—	(131)
Total liabilities	(4)	(155)	(279)	—	(438)	(4)	(253)	(535)	—	(792)
Total net assets	$ 5,945	$ 3,076	$ 1,334	$ 3,355	$13,710	$ 6,278	$ 3,049	$ 1,099	$ 3,355	$13,781

As of December 31, 2016	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
Assets										
Cash equivalents[a]	$ 39	$ —	$ —	$ —	$ 39	$ 373	$ —	$ —	$ —	$ 373
NDT fund investments										
Cash equivalents[b]	110	19	—	—	129	110	19	—	—	129
Equities	3,551	452	—	2,011	6,014	3,551	452	—	2,011	6,014
Fixed income										
Corporate debt	—	1,554	250	—	1,804	—	1,554	250	—	1,804
U.S. Treasury and agencies	1,291	29	—	—	1,320	1,291	29	—	—	1,320
Foreign governments	—	37	—	—	37	—	37	—	—	37
State and municipal debt	—	264	—	—	264	—	264	—	—	264
Other[c]	—	59	—	493	552	—	59	—	493	552
Fixed income subtotal	1,291	1,943	250	493	3,977	1,291	1,943	250	493	3,977
Middle market lending	—	—	427	71	498	—	—	427	71	498
Private equity	—	—	—	148	148	—	—	—	148	148
Real estate	—	—	—	326	326	—	—	—	326	326
NDT fund investments subtotal[d]	4,952	2,414	677	3,049	11,092	4,952	2,414	677	3,049	11,092
Pledged assets for Zion Station decommissioning										
Cash equivalents	11	—	—	—	11	11	—	—	—	11
Equities	—	2	—	—	2	—	2	—	—	2
Fixed Income — U.S. Treasury and agencies	16	1	—	—	17	16	1	—	—	17
Middle market lending	—	—	19	64	83	—	—	19	64	83
Pledged assets for Zion Station decommissioning subtotal[e]	27	3	19	64	113	27	3	19	64	113
Rabbi trust investments										
Cash equivalents	2	—	—	—	2	74	—	—	—	74
Mutual funds	19	—	—	—	19	50	—	—	—	50
Fixed income	—	—	—	—	—	—	16	—	—	16
Life insurance contracts	—	18	—	—	18	—	64	20	—	84
Rabbi trust investments subtotal	21	18	—	—	39	124	80	20	—	224

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

	Generation					Exelon				
As of December 31, 2016	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Commodity derivative assets										
Economic hedges	1,356	2,505	1,229	—	5,090	1,358	2,505	1,229	—	5,092
Proprietary trading	3	50	23	—	76	3	50	23	—	76
Effect of netting and allocation of collateral[f] [g]	(1,162)	(2,142)	(481)	—	(3,785)	(1,164)	(2,142)	(481)	—	(3,787)
Commodity derivative assets subtotal	197	413	771	—	1,381	197	413	771	—	1,381
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments	—	—	—	—	—	—	16	—	—	16
Economic hedges	—	28	—	—	28	—	28	—	—	28
Proprietary trading	3	2	—	—	5	3	2	—	—	5
Effect of netting and allocation of collateral	(2)	(19)	—	—	(21)	(2)	(19)	—	—	(21)
Interest rate and foreign currency derivative assets subtotal	1	11	—	—	12	1	27	—	—	28
Other investments	—	—	42	—	42	—	—	42	—	42
Total assets	5,237	2,859	1,509	3,113	12,718	5,674	2,937	1,529	3,113	13,253
Liabilities										
Commodity derivative liabilities										
Economic hedges	(1,267)	(2,378)	(794)	—	(4,439)	(1,267)	(2,378)	(1,052)	—	(4,697)
Proprietary trading	(3)	(50)	(26)	—	(79)	(3)	(50)	(26)	—	(79)
Effect of netting and allocation of collateral[f] [g]	1,233	2,339	542	—	4,114	1,233	2,339	542	—	4,114
Commodity derivative liabilities subtotal	(37)	(89)	(278)	—	(404)	(37)	(89)	(536)	—	(662)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments	—	(10)	—	—	(10)	—	(10)	—	—	(10)
Economic hedges	—	(21)	—	—	(21)	—	(21)	—	—	(21)
Proprietary trading	(4)	—	—	—	(4)	(4)	—	—	—	(4)
Effect of netting and allocation of collateral	4	19	—	—	23	4	19	—	—	23
Interest rate and foreign currency derivative liabilities subtotal	—	(12)	—	—	(12)	—	(12)	—	—	(12)
Deferred compensation obligation	—	(34)	—	—	(34)	—	(136)	—	—	(136)
Total liabilities	(37)	(135)	(278)	—	(450)	(37)	(237)	(536)	—	(810)
Total net assets	$ 5,200	$ 2,724	$ 1,231	$ 3,113	$12,268	$ 5,637	$ 2,700	$ 993	$ 3,113	$12,443

(a) Generation excludes cash of $238 million and $252 million at June 30, 2017 and December 31, 2016 and restricted cash of $164 million and $157 million at June 30, 2017 and December 31, 2016. Exelon excludes cash of $353 million and $360 million at June 30, 2017 and December 31, 2016 and restricted cash of $203 million and $180 million at June 30, 2017 and December 31, 2016 and includes long term restricted cash of $25 million at June 30, 2017 and December 31, 2016, which is reported in other deferred debits on the balance sheet.

(b) Includes $48 million and $29 million of cash received from outstanding repurchase agreements at June 30, 2017 and December 31, 2016, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (d) below.

(c) Includes derivative instruments of $(1) million and $(2) million, which have a total notional amount of $771 million and $933 million at June 30, 2017 and December 31, 2016, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company's exposure to credit or market loss.

(d) Excludes net liabilities of $29 million and $31 million at June 30, 2017 and December 31, 2016, 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.

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

(e) Excludes net assets of less than $1 million at June 30, 2017 and December 31, 2016. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(f) Collateral posted/(received) from counterparties totaled $71 million, $284 million and $130 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of June 30, 2017. Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled $71 million, $197 million and $61 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2016.
(g) Of the collateral posted/(received), $84 million represents variation margin on the exchanges as of June 30, 2017. Of the collateral posted/(received), $(158) million represents variation margin on the exchanges as of December 31, 2016.

ComEd, PECO and BGE

The following tables present assets and liabilities measured and recorded at fair value on ComEd's, PECO's and BGE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2017 and December 31, 2016:

	ComEd				PECO				BGE			
As of June 30, 2017	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]	$ —	$ —	$ —	$ —	$ 28	$ —	$ —	$ 28	$ 5	$ —	$ —	$ 5
Rabbi trust investments												
Mutual funds	—	—	—	—	7	—	—	7	5	—	—	5
Life insurance contracts	—	—	—	—	—	10	—	10	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	7	10	—	17	5	—	—	5
Total assets	—	—	—	—	35	10	—	45	10	—	—	10
Liabilities												
Deferred compensation obligation	—	(7)	—	(7)	—	(10)	—	(10)	—	(4)	—	(4)
Mark-to-market derivative liabilities[b]	—	—	(256)	(256)	—	—	—	—	—	—	—	—
Total liabilities	—	(7)	(256)	(263)	—	(10)	—	(10)	—	(4)	—	(4)
Total net assets (liabilities)	$ —	$ (7)	$(256)	$(263)	$ 35	$ —	$ —	$ 35	$ 10	$ (4)	$ —	$ 6

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

As of December 31, 2016	ComEd Level 1	ComEd Level 2	ComEd Level 3	ComEd Total	PECO Level 1	PECO Level 2	PECO Level 3	PECO Total	BGE Level 1	BGE Level 2	BGE Level 3	BGE Total
Assets												
Cash equivalents[(a)]	$ 20	$ —	$ —	$ 20	$ 45	$ —	$ —	$ 45	$ 36	$ —	$ —	$ 36
Rabbi trust investments												
Mutual funds	—	—	—	—	7	—	—	7	4	—	—	4
Life insurance contracts	—	—	—	—	—	10	—	10	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	7	10	—	17	4	—	—	4
Total assets	20	—	—	20	52	10	—	62	40	—	—	40
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(11)	—	(11)	—	(4)	—	(4)
Mark-to-market derivative liabilities[(b)]	—	—	(258)	(258)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(258)	(266)	—	(11)	—	(11)	—	(4)	—	(4)
Total net assets (liabilities)	$ 20	$ (8)	$(258)	$(246)	$ 52	$ (1)	$ —	$ 51	$ 40	$ (4)	$ —	$ 36

(a) ComEd excludes cash of $39 million and $36 million at June 30, 2017 and December 31, 2016 and restricted cash of $12 million and $2 million at June 30, 2017 and December 31, 2016. PECO excludes cash of $21 million and $22 million at June 30, 2017 and December 31, 2016. BGE excludes cash of $12 million and $13 million at June 30, 2017 and December 31, 2016 and restricted cash of $3 million at June 30, 2017 and includes long term restricted cash of $2 million at June 30, 2017 and December 31, 2016, which is reported in other deferred debits on the balance sheet.

(b) The Level 3 balance consists of the current and noncurrent liability of $19 million and $237 million, respectively, at June 30, 2017, and $19 million and $239 million, respectively, at December 31, 2016, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

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

PHI, Pepco, DPL and ACE

The following tables present assets and liabilities measured and recorded at fair value on 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 June 30, 2017 and December 31, 2016:

	Successor							
	As of June 30, 2017				As of December 31, 2016			
PHI	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents[a]	$ 189	$ —	$ —	$189	$ 217	$ —	$ —	$217
Mark-to-market derivative assets[b]	—	—	—	—	2	—	—	2
Effect of netting and allocation of collateral	—	—	—	—	(2)	—	—	(2)
Mark-to-market derivative assets subtotal	—	—	—	—	—	—	—	—
Rabbi trust investments								
Cash equivalents	73	—	—	73	73	—	—	73
Fixed income	—	13	—	13	—	16	—	16
Life insurance contracts	—	23	21	44	—	22	20	42
Rabbi trust investments subtotal	73	36	21	130	73	38	20	131
Total assets	262	36	21	319	290	38	20	348
Liabilities								
Deferred compensation obligation	—	(24)	—	(24)	—	(28)	—	(28)
Total liabilities	—	(24)	—	(24)	—	(28)	—	(28)
Total net assets	$ 262	$ 12	$ 21	$295	$ 290	$ 10	$ 20	$320

	Pepco				DPL				ACE			
As of June 30, 2017	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]	$ 144	$ —	$ —	$144	$ —	$ —	$ —	$—	$ 29	$ —	$ —	$ 29
Rabbi trust investments												
Cash equivalents	43	—	—	43	—	—	—	—	—	—	—	—
Fixed income	—	13	—	13	—	—	—	—	—	—	—	—
Life insurance contracts	—	23	21	44	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	43	36	21	100	—	—	—	—	—	—	—	—
Total assets	187	36	21	244	—	—	—	—	29	—	—	29
Liabilities												
Deferred compensation obligation	—	(4)	—	(4)	—	(1)	—	(1)	—	—	—	—
Total liabilities	—	(4)	—	(4)	—	(1)	—	(1)	—	—	—	—
Total net assets (liabilities)	$ 187	$ 32	$ 21	$240	$ —	$ (1)	$ —	$ (1)	$ 29	$ —	$ —	$ 29

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

As of December 31, 2016	Pepco Level 1	Pepco Level 2	Pepco Level 3	Pepco Total	DPL Level 1	DPL Level 2	DPL Level 3	DPL Total	ACE Level 1	ACE Level 2	ACE Level 3	ACE Total
Assets												
Cash equivalents[(a)]	$ 33	$ —	$ —	$ 33	$ 42	$ —	$ —	$ 42	$ 130	$ —	$ —	$130
Mark-to-market derivative assets[(b)]	—	—	—	—	2	—	—	2	—	—	—	—
Effect of netting and allocation of collateral	—	—	—	—	(2)	—	—	(2)	—	—	—	—
Mark-to-market derivative assets subtotal	—	—	—	—	—	—	—	—	—	—	—	—
Rabbi trust investments												
Cash equivalents	43	—	—	43	—	—	—	—	—	—	—	—
Fixed income	—	16	—	16	—	—	—	—	—	—	—	—
Life insurance contracts	—	22	19	41	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	43	38	19	100	—	—	—	—	—	—	—	—
Total assets	76	38	19	133	42	—	—	42	130	—	—	130
Liabilities												
Deferred compensation obligation	—	(5)	—	(5)	—	(1)	—	(1)	—	—	—	—
Total liabilities	—	(5)	—	(5)	—	(1)	—	(1)	—	—	—	—
Total net assets (liabilities)	$ 76	$ 33	$ 19	$128	$ 42	$ (1)	$ —	$ 41	$ 130	$ —	$ —	$130

(a) PHI excludes cash of $24 million and $19 million at June 30, 2017 and December 31, 2016 and includes long term restricted cash of $22 million and $23 million at June 30, 2017 and December 31, 2016 which is reported in other deferred debits on the balance sheet. Pepco excludes cash of $9 million at June 30, 2017 and December 31, 2016. DPL excludes cash of $6 million and $4 million at June 30, 2017 and December 31, 2016. ACE excludes cash of $7 million and $3 million at June 30, 2017 and December 31, 2016 and includes long term restricted cash of $22 million and $23 million at June 30, 2017 and December 31, 2016 which is reported in other deferred debits on the balance sheet.
(b) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

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

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2017 and 2016:

	Generation					ComEd	*Successor* PHI		Exelon
Three Months Ended June 30, 2017	**NDT Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total Generation**	**Mark-to-Market Derivatives[(a)]**	**Life Insurance Contracts**	**Eliminated in Consolidation**	**Total**
Balance as of March 31, 2017	$ 683	$ 20	$ 565	$ 40	$ 1,308	$ (282)	$ 20	$ —	$ 1,046
Total realized / unrealized gains (losses)									
Included in net income	1	—	(3)[(b)]	—	(2)	—	—	—	(2)
Included in noncurrent payables to affiliates	4	—	—	—	4	—	—	(4)	—
Included in payable for Zion Station decommissioning	—	1	—	—	1	—	—	—	1
Included in regulatory assets	—	—	—	—	—	26	—	4	30
Change in collateral	—	—	31	—	31	—	—	—	31
Purchases, sales, issuances and settlements									
Purchases	19	—	21	1	41	—	—	—	41
Sales	—	—	(13)	—	(13)	—	—	—	(13)
Settlements	(24)	—	—	—	(24)	—	—	—	(24)
Transfers into Level 3	—	—	(8)	—	(8)	—	—	—	(8)
Transfers out of Level 3	—	—	(4)	—	(4)	—	—	—	(4)
Balance at June 30, 2017	$ 683	$ 21	$ 589	$ 41	$ 1,334	$ (256)	$ 20	$ —	$ 1,098
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of June 30, 2017	$ —	$ —	$ 43	$ —	$ 43	$ —	$ —	$ —	$ 43

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

Six Months Ended June 30, 2017	Generation					ComEd	*Successor* PHI		Exelon
	NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives[a]	Life Insurance Contracts	Eliminated in Consolidation	Total
Balance as of December 31, 2016	$ 677	$ 19	$ 493	$ 42	$ 1,231	$ (258)	$ 20	$ —	$ 993
Total realized / unrealized gains (losses)									
Included in net income	4	—	(46)[b]	1	(41)	—	1	—	(40)
Included in noncurrent payables to affiliates	13	—	—	—	13	—	—	(13)	—
Included in payable for Zion Station decommissioning	—	1	—	—	1	—	—	—	1
Included in regulatory assets	—	—	—	—	—	2	—	13	15
Change in collateral	—	—	69	—	69	—	—	—	69
Purchases, sales, issuances and settlements									
Purchases	36	1	90	3	130	—	—	—	130
Sales	—	—	(15)	—	(15)	—	—	—	(15)
Issuances	—	—	—	—	—	—	(1)	—	(1)
Settlements	(47)	—	—	—	(47)	—	—	—	(47)
Transfers into Level 3	—	—	(10)	—	(10)	—	—	—	(10)
Transfers out of Level 3	—	—	8	(5)	3	—	—	—	3
Balance as of June 30, 2017	$ 683	$ 21	$ 589	$ 41	$ 1,334	$ (256)	$ 20	$ —	$ 1,098
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of June 30, 2017	$ 2	$ —	$ 102	$ 1	$ 105	$ —	$ 1	$ —	$ 106

(a) Includes $25 million of increases in fair value and an increase for realized losses due to settlements of $1 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended June 30, 2017. Includes $5 million of decreases in fair value and an increase for realized losses due to settlements of $7 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the six months ended June 30, 2017.

(b) Includes a reduction for the reclassification of $46 million and $148 million of realized gains due to the settlement of derivative contracts for the three and six months ended June 30, 2017.

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

Three Months Ended June 30, 2016	Generation NDT Fund Investments	Generation Pledged Assets for Zion Station Decommissioning	Generation Mark-to-Market Derivatives	Generation Other Investments	Total Generation	ComEd Mark-to-Market Derivatives [a]	*Successor* PHI Life Insurance Contracts	Eliminated in Consolidation	Exelon Total
Balance as of March 31, 2016	$ 684	$ 25	$ 1,047	$ 36	$ 1,792	$ (265)	$ 20	$ —	$ 1,547
Total realized / unrealized gains (losses)									
Included in net income	4	—	(428)[b]	—	(424)	—	1	—	(423)
Included in noncurrent payables to affiliates	8	—	—	—	8	—	—	(8)	—
Included in regulatory assets	—	—	—	—	—	44	—	8	52
Change in collateral	—	—	(32)	—	(32)	—	—	—	(32)
Purchases, sales, issuances and settlements									
Purchases	85	—	23	1	109	—	—	—	109
Sales	(1)	—	(1)	—	(2)	—	—	—	(2)
Issuances	—	—	—	—	—	—	(1)	—	(1)
Settlements	(65)	—	—	—	(65)	—	—	—	(65)
Transfers into Level 3	—	—	—	—	—	—	—	—	—
Transfers out of Level 3	—	—	—	—	—	—	—	—	—
Balance as of June 30, 2016	$ 715	$ 25	$ 609	$ 37	$ 1,386	$ (221)	$ 20	$ —	$ 1,185
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of June 30, 2016	$ 3	$ —	$ (264)	$ —	$ (261)	$ —	$ 1	$ —	$ (260)

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

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Six Months Ended June 30, 2016	Generation					ComEd	*Successor* PHI(c)		Exelon
	NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives(a)	Life Insurance Contracts	Eliminated in Consolidation	Total
Balance as of December 31, 2015	$ 670	$ 22	$ 1,051	$ 33	$ 1,776	$ (247)	$ —	$ —	$ 1,529
Included due to merger	—	—	—	—	—	—	20	—	20
Total realized / unrealized gains (losses)									
Included in net income	6	—	(434)(b)	—	(428)	—	1	—	(427)
Included in noncurrent payables to affiliates	12	—	—	—	12	—	—	(12)	—
Included in payable for Zion Station decommissioning	—	2	—	—	2	—	—	—	2
Included in regulatory assets	—	—	—	—	—	26	—	12	38
Change in collateral	—	—	(82)	—	(82)	—	—	—	(82)
Purchases, sales, issuances and settlements									
Purchases	119	1	82	4	206	—	—	—	206
Sales	(1)	—	(3)	—	(4)	—	—	—	(4)
Issuances	—	—	—	—	—	—	(1)	—	(1)
Settlements	(91)	—	—	—	(91)	—	—	—	(91)
Transfers into Level 3	—	—	2	—	2	—	—	—	2
Transfers out of Level 3	—	—	(7)	—	(7)	—	—	—	(7)
Balance as of June 30, 2016	$ 715	$ 25	$ 609	$ 37	$ 1,386	$ (221)	$ 20	$ —	$ 1,185
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of June 30, 2016	$ 4	$ —	$ (45)	$ —	$ (41)	$ —	$ 1	$ —	$ (40)

(a) Includes $40 million of increases in fair value and an increase for realized losses due to settlements of $4 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended June 30, 2016. Includes $15 million of increases in fair value and an increase for realized losses due to settlements of $11 million for the six months ended June 30, 2016.

(b) Includes a reduction for the reclassification of $164 million and $389 million of realized gains due to the settlement of derivative contracts recorded in results of operations for the three and six months ended June 30, 2016.

(c) Successor period represents activity from March 24, 2016 through June 30, 2016. See tables below for PHI's predecessor periods, as well as activity for Pepco for the three and six months ended June 30, 2017 and 2016.

PHI	*Predecessor* January 1, 2016 to March 23, 2016	
	Preferred Stock	Life Insurance Contracts
Beginning Balance	$ 18	$ 19
Total realized / unrealized gains (losses)		
Included in net income	(18)	1
Ending Balance	$ —	$ 20
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities for the period	$ —	$ 1

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

	Life Insurance Contracts			
	Three Months Ended June 30,		Six Months Ended June 30,	
Pepco	**2017**	**2016**	**2017**	**2016**
Beginning balance	$ 20	$ 20	$ 20	$ 19
Total realized / unrealized gains (losses)				
Included in net income	—	1	1	2
Purchases, sales, issuances and settlements				
Issuances	—	(1)	(1)	(1)
Ending balance	$ 20	$ 20	$ 20	$ 20
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities for the period	$ —	$ 1	$ —	$ 2

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2017 and 2016:

	Generation			*Successor* PHI	Exelon		
	Operating Revenues	Purchased Power and Fuel	Other, net[(a)]	Other, net[(a)]	Operating Revenues	Purchased Power and Fuel	Other, net[(a)]
Total gains (losses) included in net income for the three months ended June 30, 2017	$ (51)	$ 48	$ 1	$ —	$ (51)	$ 48	$ 1
Total gains (losses) included in net income for the six months ended June 30, 2017	37	(83)	5	1	37	(83)	6
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2017	—	43	—	—	—	43	—
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2017	140	(38)	3	1	140	(38)	4

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

	Generation			*Successor* PHI	Exelon		
	Operating Revenues	Purchased Power and Fuel	Other, net[(a)]	Other, net[(a)]	Operating Revenues	Purchased Power and Fuel	Other, net[(a)]
Total gains (losses) included in net income for the three months ended June 30, 2016	$ (462)	$ 34	$ 4	$ 1	$ (462)	$ 34	$ 5
Total gains (losses) included in net income for the six months ended June 30, 2016	(413)	(21)	6	1	(413)	(21)	7
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2016	(274)	10	3	1	(274)	10	4
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2016	(20)	(25)	4	1	(20)	(25)	5

	Predecessor PHI	Pepco			
	January 1, 2016 to March 23, 2016	Three Months Ended June 30,		Six Months Ended June 30,	
		2017	2016	2017	2016
	Other, net[(a)]	Other, net[(a)]			
Total gains (losses) included in net income	$ (17)	$ —	$ 1	$ 1	$ 2
Change in the unrealized gains (losses) relating to assets and liabilities held	1	—	1	1	2

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation, accrued interest on a convertible promissory note at Generation and the life insurance contracts held by PHI and Pepco.

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 (Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). The Registrants’ cash equivalents include investments with 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.

Preferred Stock Derivative (PHI). In connection with entering into the PHI Merger Agreement, PHI entered into a Subscription Agreement with Exelon dated April 29, 2014, pursuant to which PHI issued to Exelon shares of Preferred stock. The Preferred stock contained embedded features requiring separate accounting consideration to reflect the potential value to PHI that any issued and outstanding Preferred stock could be called and redeemed at a nominal par value upon a termination of the merger agreement under certain circumstances due to the failure to obtain required regulatory approvals. The embedded call and redemption features on the

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

shares of the Preferred stock in the event of such a termination were separately accounted for as derivatives. These Preferred stock derivatives were valued quarterly using quantitative and qualitative factors, including management's assessment of the likelihood of a Regulatory Termination and therefore, were categorized in Level 3 in the fair value hierarchy. As a result of the PHI Merger, the PHI Preferred stock derivative was reduced to zero as of March 23, 2016. The write-off was charged to Other, net on the PHI Consolidated Statement of Operations and Comprehensive Income.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (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 June 30, 2017, Generation has outstanding commitments to invest in middle market lending, private equity investments and real estate investments of approximately $280 million, $218 million, and $98 million, respectively. These commitments will be funded by Generation’s existing nuclear decommissioning trust funds.

Concentrations of Credit Risk. Generation evaluated its NDT portfolios for the existence of significant concentrations of credit risk as of June 30, 2017. 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 June 30, 2017, there were no significant concentrations (generally defined as greater than 10 percent) of risk in Generation’s NDT assets.

See Note 12 — Nuclear Decommissioning for further discussion on the NDT fund investments.

Rabbi Trust Investments (Exelon, Generation, PECO, BGE, PHI, Pepco, DPL and ACE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon’s executive management and directors. The Rabbi trusts assets are included in investments in the Registrants’ Consolidated Balance Sheets and consist primarily of money market funds, mutual funds, fixed income securities and life insurance policies. 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, which are typically designated as fair value hedges, 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. These interest rate derivatives are typically designated as cash flow hedges. 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 9 — Derivative Financial Instruments for further discussion on mark-to-market derivatives.

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

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

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

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. 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. 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 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 $2.86 and $0.41 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.

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

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 9 —Derivative Financial Instruments for more 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 June 30, 2017	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives — Economic Hedges (Exelon and Generation)[a][c]	$ 453	Discounted Cash Flow	Forward power price	$8 — $124
			Forward gas price	$1.92 — $9.37
		Option Model	Volatility percentage	11% — 253%
Mark-to-market derivatives — Proprietary trading (Exelon and Generation)[a][c]	$ 6	Discounted Cash Flow	Forward power price	$11 — $73
Mark-to-market derivatives (Exelon and ComEd)	$ (256)	Discounted Cash Flow	Forward heat rate[b]	9x — 10x
			Marketability reserve	3% — 8%
			Renewable factor	89% — 121%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) 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.
(c) The fair values do not include cash collateral posted on level three positions of $130 million as of June 30, 2017.

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

Type of trade	Fair Value at December 31, 2016	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives — Economic Hedges (Exelon and Generation)[(a)(c)]	$ 435	Discounted Cash Flow	Forward power price	\$11 — \$130
			Forward gas price	\$1.72 — \$9.2
		Option Model	Volatility percentage	8% — 173%
Mark-to-market derivatives — Proprietary trading (Exelon and Generation)[(a)(c)]	$ (3)	Discounted Cash Flow	Forward power price	\$19 — \$79
Mark-to-market derivatives (Exelon and ComEd)	$ (258)	Discounted Cash Flow	Forward heat rate[(b)]	8x — 9x
			Marketability reserve	3% — 8%
			Renewable factor	89% — 121%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) 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.
(c) The fair values do not include cash collateral posted on level three positions of $61 million as of December 31, 2016.

The inputs listed above 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.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (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. Generation gains an understanding of the fund managers' inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations.

Rabbi Trust Investments — Life insurance contracts (Exelon, PHI, Pepco, DPL and ACE). 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. Exelon gains an understanding of the types of inputs and assumptions used in preparing the valuations and performs procedures to assess the reasonableness of the valuations.

9. Derivative Financial Instruments (All Registrants)

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

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 energy-related products. The Registrants believe these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting 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 each period. 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 hedge, and fair value hedge. For Generation, all derivative economic hedges related to commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. The Registrants have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. Generation has also entered into bilateral long-term contractual obligations for sales of energy to load-serving entities, including electric utilities, municipalities, electric cooperatives, and retail load aggregators, as well as contractual obligations to deliver energy to market participants who primarily focus on the resale of energy products for delivery. These non-derivative contracts are accounted for primarily under the accrual method of accounting. 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.

Economic Hedging. The Registrants are exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels, and other commodities 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. 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 energy purchases, natural gas transportation and pipeline capacity agreements, and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and gas and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management's policies and hedging objectives, the market, weather conditions, operational and other factors. 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.

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 June 30, 2017, the percentage of expected generation hedged for the major reportable segments is 96%-99%, 71%-74%, and 39%-42% for 2017, 2018, and 2019, 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, which include economic hedges and certain non-derivative contracts including Generation's sales to ComEd, PECO, and BGE to serve their retail load.

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. 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 on 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 3 — Regulatory Matters of the Exelon 2016 Form 10-K for additional information.

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 5 — Regulatory Matters. Based on Pennsylvania legislation and the DSP Programs permitting PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO's price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk through full requirements contracts. PECO has certain full requirements contracts that are considered derivatives and qualify for the NPNS scope exception under current derivative authoritative guidance.

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 in order 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 2016 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 2016 PGC settlement, 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 financial position or results of operations 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. The administrative fee includes an incremental cost component and a shareholder return component for commercial and industrial rate classes. BGE's 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. All of 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 price risk related to electric supply procurement is limited. Pepco locks in fixed prices for all of 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 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 all of its SOS requirements through full requirements contracts. DPL's 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 versus the forecast 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 fifty percent (50%) of estimated purchase requirements for each month, including estimated monthly purchases for storage injections. The fifty percent (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 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. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading activities, which included settled physical sales volumes of 2,312 GWhs and 4,162 GWhs for the three and six months ended June 30, 2017, respectively, and 1,289 GWhs and 2,509 GWhs and for the three and six months June 30, 2016, respectively, are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's revenue from energy marketing activities. ComEd, PECO, BGE, PHI, Pepco, DPL and ACE do not enter into derivatives for proprietary trading purposes.

Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO, BGE and PHI)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At June 30, 2017, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding, and Exelon and Generation had $492 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in an approximately $3 million decrease in Exelon Consolidated pre-tax income for the six months ended June 30, 2017. 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. Below is a summary of the interest rate and foreign exchange hedge balances as of June 30, 2017:

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

	Generation					Exelon Corporate	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading[(a)]	Collateral and Netting[(b)]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$ —	$ 14	$ 3	$ (11)	$ 6	$ —	$ 6
Mark-to-market derivative assets (noncurrent assets)	—	3	1	(2)	2	11	13
Total mark-to-market derivative assets	—	17	4	(13)	8	11	19
Mark-to-market derivative liabilities (current liabilities)	—	(17)	(4)	11	(10)	—	(10)
Mark-to-market derivative liabilities (noncurrent liabilities)	—	(3)	—	2	(1)	—	(1)
Total mark-to-market derivative liabilities	—	(20)	(4)	13	(11)	—	(11)
Total mark-to-market derivative net assets (liabilities)	$ —	$ (3)	$ —	$ —	$ (3)	$ 11	$ 8

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on 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 counterparty exposures subject to a master netting or similar agreement, such as accrued interest, 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.

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

The following table provides a summary of the interest rate and foreign exchange hedge balances recorded by the Registrants as of December 31, 2016:

	Generation					Exelon Corporate	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading[(a)]	Collateral and Netting[(b)]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$ —	$ 17	$ 4	$ (13)	$ 8	$ —	$ 8
Mark-to-market derivative assets (noncurrent assets)	—	11	1	(8)	4	16	20
Total mark-to-market derivative assets	—	28	5	(21)	12	16	28
Mark-to-market derivative liabilities (current liabilities)	(7)	(13)	(2)	14	(8)	—	(8)
Mark-to-market derivative liabilities (noncurrent liabilities)	(3)	(8)	(2)	9	(4)	—	(4)
Total mark-to-market derivative liabilities	(10)	(21)	(4)	23	(12)	—	(12)
Total mark-to-market derivative net assets (liabilities)	$ (10)	$ 7	$ 1	$ 2	$ —	$ 16	$ 16

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on 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 counterparty exposures subject to a master netting or similar agreement, such as accrued interest, 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.

Fair Value Hedges. For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings. Exelon includes the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps in interest expense as follows:

		Three Months Ended June 30,			
		2017	2016	2017	2016
	Income Statement Location	Gain (loss) on Swaps		Gain (loss) on Borrowings	
Exelon	Interest expense	$ 1	$ 5	$ 2	$ (1)

		Six Months Ended June 30,			
		2017	2016	2017	2016
	Income Statement Location	Gain (loss) on Swaps		Gain (loss) on Borrowings	
Exelon	Interest expense	$ (4)	$ 22	$ 10	$ (16)

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

At June 30, 2017, Exelon had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $800 million, with a derivative asset of $11 million. At December 31, 2016, Exelon had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $800 million, with a derivative asset of $16 million. During the three and six months ended June 30, 2017 and 2016, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $3 million gain, a $7 million gain, a $4 million gain, and a $6 million gain, respectively.

Cash Flow Hedges. During the first and second quarter of 2016, Exelon entered into $600 million and $100 million of floating-to-fixed forward starting interest rate swaps, respectively, to manage a portion of the interest rate exposure associated with an anticipated debt issuance. The swaps were designated as cash flow hedges. Exelon terminated the swaps during the second quarter of 2016 upon issuance of the debt. Exelon recognized a loss of $3 million related to the swaps and $3 million of AOCI will be amortized into Other, net in Exelon's Consolidated Statement of Operations and Comprehensive Income over the term of the debt. See Note 10 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

During the first quarter of 2016, Exelon entered into a $100 million floating-to-fixed forward starting interest rate swaps to manage a portion of the interest rate exposure associated with an anticipated debt issuance. The swap was designated as a cash flow hedge. Exelon terminated the swap during the first quarter of 2016 upon issuance of the debt. Exelon did not recognize a gain or loss as a result of the termination of the swap and an immaterial amount of AOCI will be amortized into Other, net in Exelon's Consolidated Statement of Operations and Comprehensive Income over the term of the debt.

During the first quarter of 2014, EGR, a subsidiary of Generation, entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with its long-term borrowings. The swaps were de-designated as cash flow hedges and, during the second quarter of 2017, upon termination of the debt, Generation terminated the swaps. The total notional amount of the swaps was $164 million. No gain or loss was recognized as a result of the termination of the swaps. See Note 10 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

During the three and six months ended June 30, 2017 and 2016, the impact on the results of operations as a result of ineffectiveness from cash flow hedges in continuing designated hedge relationships was immaterial.

Economic Hedges. During the third quarter of 2014, EGTP, a subsidiary of Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with the long-term borrowing. See Note 14 — Debt and Credit Agreements of the Exelon 2016 Form 10-K for additional information regarding the financing. The swaps have a notional amount of $492 million as of June 30, 2017 and expire in 2019. The swap was designated as a cash flow hedge in the fourth quarter of 2014. During the first quarter of 2017, the swap was de-designated. At June 30, 2017, the subsidiary had a $8 million derivative liability related to the swap.

During the third quarter of 2011, Sacramento PV Energy, a subsidiary of Generation entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 14 — Debt and Credit Agreements of the Exelon 2016 Form 10-K for additional information regarding the financing. During the first quarter of 2016, upon the termination of debt, Generation terminated the swaps. The total notional amount of the swaps was $25 million. No gain or loss was recognized as a result of the termination of the swaps.

During the third quarter of 2012, Constellation Solar Horizons, a subsidiary of Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 14 — Debt and Credit Agreements of the Exelon 2016 Form 10-K for additional information regarding the financing. During the first quarter of 2016, upon the termination of debt, Generation terminated the swap. The total notional amount of the swap was $24 million. No gain or loss was recognized as a result of the termination of the swap.

At June 30, 2017, Generation had immaterial notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $103 million in notional amounts of foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

Fair Value Measurement and Accounting for the Offsetting of Amounts Related to Certain Contracts (Exelon, Generation, ComEd, PECO, BGE, PHI and DPL)

Fair value accounting guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to the 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 June 30, 2017 and December 31, 2016, $2 million and $8 million of cash collateral held, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives, were associated with accrual positions, or as of the balance sheet date there were no positions to offset. 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 a non affiliate major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

In the table below, DPL's economic hedges 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, is aggregated in the collateral and netting column.

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

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The following table provides a summary of the derivative fair value balances recorded by the Registrants as of June 30, 2017:

	Generation				ComEd	DPL			*Successor* PHI	Exelon
Derivatives	**Economic Hedges**	**Proprietary Trading**	**Collateral and Netting[(a)] [(e)]**	**Subtotal[(b)]**	**Economic Hedges[(c)]**	**Economic Hedges[(d)]**	**Collateral and Netting[(a)]**	**Subtotal**	**Subtotal**	**Total Derivatives**
Mark-to-market derivative assets (current assets)	$ 3,198	$ 58	$ (2,429)	$ 827	$ —	$ —	$ —	$ —	$ —	$ 827
Mark-to-market derivative assets (noncurrent assets)	1,736	23	(1,308)	451	—	—	—	—	—	451
Total mark-to-market derivative assets	4,934	81	(3,737)	1,278	—	—	—	—	—	1,278
Mark-to-market derivative liabilities (current liabilities)	(2,895)	(52)	2,732	(215)	(19)	—	—	—	—	(234)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,644)	(25)	1,490	(179)	(237)	—	—	—	—	(416)
Total mark-to-market derivative liabilities	(4,539)	(77)	4,222	(394)	(256)	—	—	—	—	(650)
Total mark-to-market derivative net assets (liabilities)	$ 395	$ 4	$ 485	$ 884	$ (256)	$ —	$ —	$ —	$ —	$ 628

(a) Exelon, Generation, PHI and DPL net all available amounts allowed under the derivative accounting guidance on 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 $149 million and $74 million, respectively, and current and noncurrent liabilities are shown net of collateral of $155 million and $107 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $485 million at June 30, 2017.

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

(d) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

(e) Of the collateral posted/(received), $84 million represents variation margin on the exchanges.

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

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2016:

	Generation				ComEd	DPL			*Successor* PHI	Exelon
Description	Economic Hedges	Proprietary Trading	Collateral and Netting[(a)] [(e)]	Subtotal[(b)]	Economic Hedges[(c)]	Economic Hedges[(d)]	Collateral and Netting[(a)]	Subtotal	Subtotal	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 3,623	$ 55	$ (2,769)	$ 909	$ —	$ 2	$ (2)	$ —	$ —	$ 909
Mark-to-market derivative assets (noncurrent assets)	1,467	21	(1,016)	472	—	—	—	—	—	472
Total mark-to-market derivative assets	5,090	76	(3,785)	1,381	—	2	(2)	—	—	1,381
Mark-to-market derivative liabilities (current liabilities)	(3,165)	(54)	2,964	(255)	(19)	—	—	—	—	(274)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,274)	(25)	1,150	(149)	(239)	—	—	—	—	(388)
Total mark-to-market derivative liabilities	(4,439)	(79)	4,114	(404)	(258)	—	—	—	—	(662)
Total mark-to-market derivative net assets (liabilities)	$ 651	$ (3)	$ 329	$ 977	$ (258)	$ 2	$ (2)	$ —	$ —	$ 719

(a) Exelon, Generation, PHI and DPL net all available amounts allowed under the derivative accounting guidance on 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 $100 million and $72 million, respectively, and current and noncurrent liabilities are shown net of collateral of $95 million and $62 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $329 million at December 31, 2016.
(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.
(d) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.
(e) Of the collateral posted/(received), $(158) million represents variation margin on the exchanges.

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

Cash Flow Hedges (Exelon and Generation). The tables below provide the activity of OCI related to cash flow hedges for the six months ended June 30, 2017 and 2016, containing information about the changes in the fair value of cash flow hedges and the reclassification from Accumulated OCI into results of operations. The amounts reclassified from OCI, when combined with the impacts of the hedged transactions, result in the ultimate recognition of net revenues or expenses at the contractual price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended June 30, 2017	Income Statement Location	Total Cash Flow Hedges	Total Cash Flow Hedges
Accumulated OCI derivative loss at March 31, 2017		$ (13)	$ (11)
Effective portion of changes in fair value		(1)	(1)
Accumulated OCI derivative loss at June 30, 2017		$ (14)	$ (12)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Six Months Ended June 30, 2017	Income Statement Location	Total Cash Flow Hedges	Total Cash Flow Hedges
Accumulated OCI derivative loss at December 31, 2016		$ (19)	$ (17)
Effective portion of changes in fair value		1	1
Reclassifications from AOCI to net income	Interest Expense	4[(a)]	4[(a)]
Accumulated OCI derivative loss at June 30, 2017		$ (14)	$ (12)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended June 30, 2016	Income Statement Location	Total Cash Flow Hedges	Total Cash Flow Hedges
Accumulated OCI derivative loss at March 31, 2016		$ (26)	$ (26)
Reclassifications from AOCI to net income	Interest Expense	1	—
Accumulated OCI derivative loss at June 30, 2016		$ (25)	$ (26)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Six Months Ended June 30, 2016	Income Statement Location	Total Cash Flow Hedges	Total Cash Flow Hedges
Accumulated OCI derivative loss at December 31, 2015		$ (21)	$ (19)
Effective portion of changes in fair value		(7)	(10)
Reclassifications from AOCI to net income	Interest Expense	3[(b)]	3[(b)]
Accumulated OCI derivative loss at June 30, 2016		$ (25)	$ (26)

(a) Amount is net of related income tax expense of $3 million for the six months ended June 30, 2017.
(b) Amount is net of related income tax expense of $2 million for the six months ended June 30, 2016.

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

Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, physical forward sales and purchases, but for which the fair value or cash flow hedge elections were not made. Additionally, Generation enters into interest rate derivative contracts and foreign exchange currency swaps ("treasury") to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars. For the three and six months ended June 30, 2017 and 2016, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in Operating revenues or Purchased power and fuel expense, or Interest expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized" generally represents the recognized change in fair value that was reclassified from unrealized to realized when the transaction to which the derivative relates occurs.

	Generation			Exelon
Three Months Ended June 30, 2017	Operating Revenues	Purchased Power and Fuel	Total	Total
Change in fair value of commodity positions	$ (100)	$ (62)	$(162)	$(162)
Reclassification to realized at settlement of commodity positions	(41)	21	(20)	(20)
Net commodity mark-to-market gains (losses)	(141)	(41)	(182)	(182)
Change in fair value of treasury positions	(2)	—	(2)	(2)
Reclassification to realized at settlement of treasury positions	—	—	—	—
Net treasury mark-to-market gains (losses)	(2)	—	(2)	(2)
Net mark-to-market gains (losses)	$ (143)	$ (41)	$(184)	$(184)

	Generation			Exelon
Six Months Ended June 30, 2017	Operating Revenues	Purchased Power and Fuel	Total	Total
Change in fair value of commodity positions	$ (9)	$ (197)	$(206)	$(206)
Reclassification to realized of commodity positions	(87)	63	(24)	(24)
Net commodity mark-to-market gains (losses)	(96)	(134)	(230)	(230)
Change in fair value of treasury positions	(1)	—	(1)	(1)
Reclassification to realized of treasury positions	(2)	—	(2)	(2)
Net treasury mark-to-market gains (losses)	(3)	—	(3)	(3)
Net mark-to-market gains (losses)	$ (99)	$ (134)	$(233)	$(233)

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

Three Months Ended June 30, 2016	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Total	Exelon Total
Change in fair value of commodity positions	$ (432)	$ 235	$(197)	$(197)
Reclassification to realized at settlement of commodity positions	(181)	76	(105)	(105)
Net commodity mark-to-market gains (losses)	(613)	311	(302)	(302)
Change in fair value of treasury positions	1	—	1	1
Reclassification to realized at settlement of treasury positions	(3)	—	(3)	(3)
Net treasury mark-to-market gains (losses)	(2)	—	(2)	(2)
Net mark-to-market gains (losses)	$ (615)	$ 311	$(304)	$(304)

Six Months Ended June 30, 2016	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Total	Exelon Total
Change in fair value of commodity positions	$ (153)	$ 109	$ (44)	$ (44)
Reclassification to realized of commodity positions	(392)	243	(149)	(149)
Net commodity mark-to-market gains (losses)	(545)	352	(193)	(193)
Change in fair value of treasury positions	(4)	—	(4)	(4)
Reclassification to realized of treasury positions	(4)	—	(4)	(4)
Net treasury mark-to-market gains (losses)	(8)	—	(8)	(8)
Net mark-to-market gains (losses)	$ (553)	$ 352	$(201)	$(201)

Proprietary Trading Activities (Exelon and Generation). For the three and six months ended June 30, 2017 and 2016, Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) before income taxes relating to mark-to-market activity on commodity derivative instruments entered into for proprietary trading purposes and interest rate and foreign exchange derivative contracts to hedge risk associated with the interest rate and foreign exchange components of underlying commodity positions. Gains and losses associated with proprietary trading are reported as operating revenues in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Change in fair value of commodity positions	$ 6	$ 5	$ 6	$ 14
Reclassification to realized of commodity positions	(6)	(5)	(7)	(11)
Net commodity mark-to-market gains (losses)	—	—	(1)	3
Change in fair value of treasury positions	—	—	(1)	(2)
Reclassification to realized of treasury positions	—	(1)	—	1
Net treasury mark-to-market gains (losses)	—	(1)	(1)	(1)
Total net mark-to-market gains (losses)	$ —	$ (1)	$ (2)	$ 2

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

Credit Risk (All Registrants)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of June 30, 2017. 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 $23 million, $27 million, $21 million, $41 million, $12 million, and $6 million as of June 30, 2017, respectively.

Rating as of June 30, 2017	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	$ 878	$ 14	$ 864	1	$ 299
Non-investment grade	47	1	46	—	—
No external ratings					
Internally rated — investment grade	327	—	327	—	—
Internally rated — non-investment grade	123	14	109	—	—
Total	$ 1,375	$ 29	$ 1,346	1	$ 299

Net Credit Exposure by Type of Counterparty	As of June 30, 2017
Financial institutions	$ 89
Investor-owned utilities, marketers, power producers	563
Energy cooperatives and municipalities	560
Other	134
Total	$ 1,346

(a) As of June 30, 2017, credit collateral held from counterparties where Generation had credit exposure included $19 million of cash and $10 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 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, 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 June 30, 2017, ComEd's net credit exposure to suppliers was approximately $1 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 3 — Regulatory Matters of the Exelon 2016 Form 10-K for additional information.

PECO's supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements 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 PECO's net credit exposure. As of June 30, 2017, PECO had no material net credit exposure to suppliers.

PECO is permitted to recover its costs of procuring electric supply through its PAPUC-approved DSP Program. PECO's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 5 — Regulatory Matters for additional information.

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. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of June 30, 2017, 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 3 — Regulatory Matters of the Exelon 2016 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. 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, subject to an unsecured credit cap. 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 BGE's net credit exposure. The seller's credit exposure is calculated each business day. As of June 30, 2017, BGE had no net credit exposure to suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At June 30, 2017, BGE had credit exposure of less than $1 million 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.

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 June 30, 2017, 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 3 — Regulatory Matters of the Exelon 2016 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 June 30, 2017, DPL had no credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

Collateral and Contingent-Related Features (All Registrants)

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of electric capacity, energy, 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 (i.e., NYMEX, ICE). 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.

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

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

Credit-Risk Related Contingent Feature	June 30, 2017	December 31, 2016
Gross Fair Value of Derivative Contracts Containing this Feature[(a)]	$ (942)	$ (960)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements[(b)]	601	627
Net Fair Value of Derivative Contracts Containing This Feature[(c)]	$ (341)	$ (333)

(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 $517 million and letters of credit posted of $278 million and cash collateral held of $34 million and letters of credit held of $21 million as of June 30, 2017 for external counterparties with derivative positions. Generation had cash collateral posted of $347 million and letters of credit posted of $284 million and cash collateral held of $24 million and letters of credit held of $28 million at December 31, 2016 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 $1.8 billion and $1.9 billion as of June 30, 2017 and December 31, 2016, respectively. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if Generation'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 June 30, 2017, Generation's swaps were in a liability position with a fair value of $3 million and Exelon's swaps were in an asset position, with a fair value of $8 million.

See Note 26 — Segment Information of the Exelon 2016 Form 10-K for further 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 June 30, 2017, ComEd held approximately $13 million in collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, 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 June 30, 2017, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. If ComEd lost its investment grade credit rating as of June 30, 2017, it would have been required to post approximately $12 million of collateral to its counterparties. See Note 3 — Regulatory Matters of the Exelon 2016 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 from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of June 30, 2017, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of June 30, 2017, PECO could have been required to post approximately $21 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 full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE 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 June 30, 2017, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of June 30, 2017, BGE could have been required to post approximately $36 million of collateral to its counterparties.

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

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

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 June 30, 2017, DPL could have been required to post an additional amount of approximately $10 million of collateral to its natural gas counterparties.

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

10. Debt and Credit Agreements (All Registrants)

Short-Term Borrowings

Exelon, Pepco, DPL and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and short-term notes. ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. PHI meets its short-term liquidity requirement primarily through the issuance of short-term notes and the Exelon intercompany money pool.

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

Commercial Paper

The Registrants had the following amounts of commercial paper borrowings outstanding as of June 30, 2017 and December 31, 2016:

Commercial Paper Borrowings	June 30, 2017	December 31, 2016
Exelon Corporate	$ —	$ —
Generation	569	620
ComEd	389	—
BGE	85	45
Pepco	—	23
DPL	25	—
ACE	42	—

Short-Term Loan Agreements

On January 13, 2016, PHI entered into a $500 million term loan agreement, which was amended on March 28, 2016. The net proceeds of the loan were used to repay PHI’s outstanding commercial paper, and for general corporate purposes. Pursuant to the loan agreement, as amended, loans made thereunder bear interest at a variable rate equal to LIBOR plus 1%, and all indebtedness thereunder is unsecured. On March 23, 2017, the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement was fully repaid and the loan terminated. On March 23, 2017, Exelon Corporate entered into a similar type term loan for $500 million which expires on March 22, 2018. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 1% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon’s Consolidated Balance Sheet within Short-Term borrowings.

Credit Agreements

On January 9, 2017, the credit agreement for Generation’s $75 million bilateral credit facility was amended and restated to increase the facility size to $100 million and extend the maturity to January 2019. This facility will solely be used by Generation to issue letters of credit.

On May 26, 2016, Exelon Corporate, Generation, ComEd, PECO and BGE entered into amendments to each of their respective syndicated revolving credit facilities, which extended the maturity of each of the facilities to May 26, 2021. Exelon Corporate also increased the size of its facility from $500 million to $600 million. On May 26, 2016, PHI, Pepco, DPL and ACE entered into an amendment to their Second Amended and Restated Credit Agreement dated as of August 1, 2011, which (i) extended the maturity date of the facility to May 26, 2021, (ii) removed PHI as a borrower under the facility, (iii) decreased the size of the facility from $1.5 billion to $900 million and (iv) converted its financial covenant from a debt to capitalization leverage ratio to an interest coverage ratio. On May 26, 2017, each of the Registrants’ respective syndicated revolving credit facilities had their maturity dates extended to May 26, 2022.

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

Long-Term Debt

Issuance of Long-Term Debt

During the six months ended June 30, 2017, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Junior Subordinated Notes [(a)]	3.50%	June 1, 2022	$ 1,150	Refinance Exelon's Junior Subordinated Notes issued in June 2014.
Generation	Albany Green Energy Project Financing	LIBOR + 1.25%	November 17, 2017	$ 13	Albany Green Energy biomass generation development.
Generation	Energy Efficiency Project Financing	3.90%	February 1, 2018	$ 12	Funding to install energy conservation measures for the Naval Station Great Lakes project.
Generation	Energy Efficiency Project Financing	2.61%	September 30, 2018	$ 6	Funding to install energy conservation measures for the Pensacola project.
Generation	Energy Efficiency Project Financing	3.53%	April 1, 2019	$ 8	Funding to install energy conservation measures for the State Department project.
Generation	Energy Efficiency Project Financing	3.72%	May 1, 2018	$ 3	Funding to install energy conservation measures for the Smithsonian Zoo project.
Generation	Senior Notes	2.95%	January 15, 2020	$ 250	Repay outstanding commercial paper obligations and for general corporate purposes.
Generation	Senior Notes	3.40%	March 15, 2022	$ 500	Repay outstanding commercial paper obligations and for general corporate purposes.
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.75%	September 18, 2021	$ 6	Funding for general corporate purposes.
Pepco	Energy Efficiency Project Financing	3.30%	December 15, 2017	$ 1	Funding to install energy conservation measures for the DOE Germantown project.
Pepco	First Mortgage Bonds	4.15%	March 15, 2043	$ 200	Funding to repay outstanding commercial paper and for general corporate purposes.

(a) See the Junior Subordinated Notes discussion below for further information.

EGTP Nonrecourse Debt

In September 2014, EGTP, an indirect subsidiary of Exelon and Generation, issued $675 million aggregate principal amount of a nonrecourse senior secured term loan. The net proceeds were distributed to Generation for general business purposes. The loan is scheduled to mature on September 18, 2021. The term loan bears interest at a variable rate equal to LIBOR plus 4.75%, subject to a 1% LIBOR floor with interest payable quarterly. As of June 30, 2017, $662 million was outstanding. As part of the agreement, a revolving credit facility was established for the amount of $20 million available through, and scheduled to mature on September 18, 2019. In addition to the financing, EGTP entered into various interest rate swaps with an initial notional amount of approximately $505 million at an interest rate of 2.34% to hedge a portion of the interest rate exposure in connection with this financing, as required by the debt covenants. See Note 9 — Derivative Financial Instruments for additional information regarding interest rate swaps.

On May 2, 2017, EGTP entered into a consent agreement with its lenders, which resulted in the outstanding debt balance being classified as Long-term debt due within one year on Exelon’s and Generation’s Consolidated Balance Sheets. See Note 4 — Mergers, Acquisitions and Dispositions and Note 6 — Impairment of Long-Lived Assets for more information.

Junior Subordinated Notes

In June 2014, Exelon issued $1.15 billion of junior subordinated notes in the form of 23 million equity units at a stated amount of $50.00 per unit. Each equity unit represented an undivided beneficial ownership interest in Exelon’s $1.15 billion of 2.50% junior subordinated notes due in 2024 (“2024 notes”) and a forward equity purchase contract. As contemplated in the June 2014 equity unit structure, in April 2017, Exelon completed the remarketing of the 2024 notes into $1.15 billion of 3.497% junior subordinated notes due in 2022 (“Remarketing”). Exelon conducted the Remarketing on behalf of the holders of equity units and did not directly receive any proceeds therefrom. Instead, the former holders of the 2024 notes used debt remarketing proceeds towards settling the forward equity purchase contract with Exelon on June 1, 2017. Exelon issued approximately 33 million shares of common stock from treasury stock and received $1.15 billion upon settlement of the forward equity purchase contract. When reissuing treasury stock Exelon uses the average price paid to repurchase shares to calculate a gain or loss on issuance and records gains or losses directly to retained earnings. A loss on reissuance of treasury shares of $1.05 billion was recorded to retained earnings as of June 30, 2017. See Note 16 — Earnings Per Share and Equity for further information on the issuance of common stock.

BGE Redemption of Trust Preferred Securities

On August 1, 2017, BGE announced that it intends to redeem all of the outstanding shares of BGE Capital Trust II 6.20% Preferred Securities, which totaled $258 million at June 30, 2017. The securities will be redeemed on August 28, 2017, pursuant to the optional redemption provisions of the Indenture under which the securities were issued. The redemption will be made to stockholders of record as of the close of business on August 25, 2017. The redemption price per share is $25.19, which equals the stated value per share plus accrued and unpaid dividends to, but excluding, the redemption date. No dividends on the Securities being redeemed will accrue on or after the redemption date, nor will any interest accrue on amounts held to pay the redemption price.

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

11. Income Taxes (All Registrants)

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

	Three Months Ended June 30, 2017								
									Successor
	Exelon[(a)]	Generation[(b)]	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	(2,745.7)	5.6	5.8	(0.6)	5.0	3.2	4.6	5.6	4.3
Qualified nuclear decommissioning trust fund income	3,156.6	(6.3)	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(528.7)	0.9	(0.2)	(0.1)	(0.2)	(0.1)	(0.1)	(0.4)	(0.1)
Plant basis differences	(2,764.4)	—	(0.2)	(16.0)	(0.3)	(6.2)	(1.7)	(3.3)	(4.8)
Production tax credits and other credits	(1,035.7)	2.0	—	—	—	—	—	—	—
Noncontrolling interests	84.7	(0.2)	—	—	—	—	—	—	—
Like-kind exchange[(c)]	(5,362.4)	—	5.9	—	—	—	—	—	—
Other	1,960.6	1.1	0.5	0.2	1.3	(0.2)	0.9	(3.6)	0.9
Effective income tax rate	(7,200.0)%	38.1%	46.8%	18.5%	40.8%	31.7%	38.7%	33.3%	35.3%

	Three Months Ended June 30, 2016								
									Successor
	Exelon	Generation[(d)]	ComEd	PECO	BGE[(e)]	Pepco	DPL	ACE	PHI
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	2.3	(116.7)	4.8	0.3	2.0	3.5	4.8	5.9	6.1
Qualified nuclear decommissioning trust fund income	5.7	591.2	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.8)	(157.8)	(0.2)	(0.1)	(0.4)	(0.1)	(0.6)	(1.6)	(0.3)
Plant basis differences[(f)]	(6.9)	—	(0.4)	(11.3)	(20.6)	(5.7)	(3.5)	(7.1)	(7.0)
Production tax credits and other credits	(5.8)	(603.0)	—	—	—	—	—	—	—
Noncontrolling interest	0.9	94.4	—	—	—	—	—	—	—
Statute of limitations expiration	(1.7)	(410.8)	—	—	—	—	—	—	—
Merger expenses	0.2	—	—	—	—	0.2	3.1	—	1.0
Other[(g)]	(3.3)	(52.3)	(0.6)	(5.2)	(1.0)	(1.0)	1.2	7.8	1.0
Effective income tax rate	24.6%	(620.0)%	38.6%	18.7%	15.0%	31.9%	40.0%	40.0%	35.8%

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

	Six Months Ended June 30, 2017								
									Successor
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	(1.0)	(13.6)	5.3	(0.1)	5.1	3.8	5.1	5.6	4.6
Qualified nuclear decommissioning trust fund income	5.6	51.2	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(0.7)	(5.4)	(0.2)	(0.1)	(0.1)	(0.1)	(0.2)	(0.4)	(0.2)
Plant basis differences	(4.3)	—	(0.2)	(14.3)	(0.7)	(6.0)	(1.8)	(3.3)	(4.3)
Production tax credits and other credits	(1.4)	(12.3)	—	—	—	—	—	—	—
Noncontrolling interests	(0.1)	(0.5)	—	—	—	—	—	—	—
Merger expenses(h)	(11.4)	(13.7)	—	—	—	(16.2)	(15.1)	(85.3)	(23.8)
Fitzpatrick bargain purchase gain	(6.5)	(60.0)	—	—	—	—	—	—	—
Like-kind exchange(c)	(3.7)	—	2.9	—	—	—	—	—	—
Other	0.3	(4.2)	0.4	(0.1)	0.3	(0.7)	1.0	(1.6)	—
Effective income tax rate	11.8%	(23.5)%	43.2%	20.4%	39.6%	15.8%	24.0%	(50.0)%	11.3%

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

	Six Months Ended June 30, 2016								*Successor* March 24, 2016 to June 30, 2016	*Predecessor* January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco[i]	DPL[i]	ACE[i]	PHI[i]	PHI
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:										
State income taxes, net of Federal income tax benefit[j]	0.8	2.6	4.9	0.7	4.6	(9.5)	(5.2)	5.9	5.2	11.9
Qualified nuclear decommissioning trust fund income	5.6	9.8	—	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.7)	(2.5)	(0.2)	(0.1)	(0.1)	0.1	0.4	0.1	0.1	(0.9)
Plant basis differences[f]	(6.3)	—	(0.3)	(10.2)	(4.5)	12.6	2.0	1.0	1.7	(13.5)
Production tax credits and other credits	(5.5)	(9.6)	—	—	—	—	—	—	—	—
Noncontrolling interest	0.7	1.2	—	—	—	—	—	—	—	—
Statute of limitations expiration	(1.0)	(3.9)	—	—	—	—	—	—	—	—
Merger expenses	14.5	—	—	—	—	(36.1)	(30.5)	(17.7)	(18.9)	11.1
Other[g]	(2.8)	(3.8)	(0.1)	(2.4)	0.1	(0.5)	(0.1)	(0.1)	—	3.6
Effective income tax rate	39.3%	28.8%	39.3%	23.0%	35.1%	1.6%	1.6%	24.2%	23.1%	47.2%

(a) The effective tax rate for the three months ended June 30, 2017 is disproportionately impacted due to the decline in consolidated pre-tax GAAP earnings as compared to the federal and state tax impacts of the Like-kind exchange, tax credits, Plant basis differences, and Qualified nuclear decommissioning trust fund income.
(b) Generation recognized a loss before income taxes for the three months ended June 30, 2017. As a result, positive percentages represent an income tax benefit for the period presented.
(c) See Like-Kind Exchange within the Other Income Tax Matters section below for further details.
(d) The effective tax rate for the three months ended June 30, 2016, is disproportionately impacted due to the decline in pre-tax GAAP earnings as compared to the changes in tax credits and other reconciling items. In three months ended June 30, 2016, due to the expiration of a statute of limitations, Generation recorded an income tax benefit of $16 million. The statute of limitations expired in the third quarter of 2015; therefore, this represents an out of period adjustment.
(e) The effective tax rate for the three months ended June 30, 2016 is disproportionately impacted due to the decline in pre-tax GAAP earnings and changes in other reconciling items.
(f) At BGE, includes a cumulative adjustment related to a regulatory asset.
(g) At PECO, includes a cumulative adjustment related to an anticipated gas repairs tax return accounting method change.
(h) Includes a remeasurement of uncertain federal and state income tax positions, see below.
(i) Pepco, DPL and ACE recognized a loss before income taxes for the six months ended June 30, 2016, and PHI recognized a loss before income taxes for the period of March 24, 2016, through June 30, 2016. As a result, positive percentages represent an income tax benefit for the periods presented.
(j) Includes a remeasurement of uncertain state income tax positions for Pepco and DPL.

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

Accounting for Uncertainty in Income Taxes

The Registrants have the following unrecognized tax benefits as of June 30, 2017 and December 31, 2016:

	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
June 30, 2017	$ 730	$ 467	$ 2	$ —	$120	$ 112	$ 59	$21	$ —

	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
December 31, 2016	$ 916	$ 490	$ (12)	$ —	$120	$ 172	$ 80	$37	$ 22

Exelon established a liability for an uncertain tax position associated with the tax deductibility of certain merger commitments incurred by Exelon in connection with the acquisitions of Constellation in 2012 and PHI in 2016. In the first quarter 2017, as a part of its examination of Exelon's return, the IRS National Office issued guidance concurring with Exelon's position that the merger commitments were deductible. As a result, Exelon, Generation, PHI, Pepco, DPL, and ACE decreased their liability for unrecognized tax benefits by $146 million, $19 million, $59 million, $21 million, $16 million, and $22 million, respectively, as of June 30, 2017, resulting in a benefit to Income taxes on Exelon's, Generation's, PHI's, Pepco's, DPL's and ACE's Consolidated Statements of Operations and Comprehensive Income and corresponding decreases in their effective tax rates.

Exelon reduced the liability related to the uncertain tax position associated with the like-kind exchange in the second quarter of 2017. Please see the Other Income Tax Matters section below for additional details related to the like-kind exchange adjustments made in the second quarter of 2017.

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

Like-Kind Exchange

As of June 30, 2017, Exelon and ComEd have approximately $39 million and $2 million, respectively, of unrecognized federal and state income tax benefits that could significantly decrease within the 12 months after the reporting date due to a final resolution of the like-kind exchange litigation described below. The recognition of these unrecognized tax benefits would decrease Exelon and ComEd's effective tax rate.

Settlement of Income Tax Audits

As of June 30, 2017, Exelon, Generation, BGE, PHI, Pepco, and DPL have approximately $257 million, $57 million, $120 million, $80 million, $59 million, and $21 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 and potential settlements. Of the above unrecognized tax benefits, Exelon and Generation have $50 million that, if recognized, would decrease the effective tax rate. The unrecognized tax benefits related to BGE, DPL, and a portion of Pepco, if recognized, may be included in future regulated base rates and that portion would have no impact to the effective tax rate.

Other Income Tax Matters

Like-Kind Exchange (Exelon and ComEd)

Exelon, through its ComEd subsidiary, took a position on its 1999 income tax return to defer approximately $1.2 billion of tax gain on the sale of ComEd's fossil generating assets. The gain was deferred by reinvesting a portion of the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities.

The IRS disagreed with this position and asserted that the entire gain of approximately $1.2 billion was taxable in 1999. Exelon was unable to reach agreement with the IRS regarding the dispute over the like-kind exchange position. The IRS asserted that the Exelon purchase and leaseback transaction was substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a "listed transaction" that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities did not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS also asserted a penalty of approximately $90 million for a substantial understatement of tax.

On September 30, 2013, the IRS issued a notice of deficiency to Exelon for the like-kind exchange position. Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court (Tax Court) and the trial took place in August of 2015. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the issue.

On September 19, 2016, the Tax Court rejected Exelon's position in the case and ruled that Exelon was not entitled to defer gain on the transaction. In addition, contrary to Exelon's evaluation that the penalty was unwarranted, the Tax Court ruled that Exelon is liable for the penalty and interest due on the asserted penalty. Exelon expects to timely appeal this decision to the U.S. Court of Appeals for the Seventh Circuit in the second half of 2017. In June of 2017, the IRS finalized its computation of tax, penalties and interest owed by Exelon pursuant to the Tax Court's decision.

In the first quarter of 2013, Exelon concluded that it was no longer more likely than not that the like-kind exchange position would be sustained and recorded charges to earnings representing the amount of interest expense (after-tax) and incremental state income tax expense that would be payable in the event Exelon is unsuccessful in litigation. Exelon agreed to hold ComEd harmless from any unfavorable impacts on ComEd's equity of the after-tax interest and penalty amounts.

Prior to the Tax Court's decision, however, Exelon did not believe it was likely a penalty would be assessed based on applicable case law and the facts of the transaction. As a result, no charge had been recorded for the penalty or for after-tax interest on the penalty. While it has strong arguments on appeal with respect to both the merits and the penalty, Exelon has determined that, pursuant to accounting standards, it is no longer more likely than not to avoid ultimate imposition of the penalty. As a result, in the third quarter of 2016, Exelon and ComEd recorded a charge to earnings of approximately $106 million and $86 million, respectively, of penalty and approximately $94 million and $64 million, respectively, of after-tax interest. Exelon and ComEd recorded the penalty and pre-tax interest due on the asserted penalty to Other, net and Interest expense, net, respectively, on their Consolidated Statements of Operations. Consistent with Exelon's agreement to continue to hold ComEd harmless from any unfavorable impact on its equity from the like-kind exchange position, ComEd recorded on its Consolidated Balance Sheets as of September 30, 2016, a $150 million receivable and non-cash equity contributions from Exelon.

As a result of the IRS's finalization of its computation in the second quarter 2017, Exelon recorded a benefit to earnings of approximately $26 million, consisting of an income tax benefit of $50 million and a reduction of penalties of $2 million, partially offset by after-tax interest expense of $26 million, while ComEd recorded a charge to earnings of approximately $23 million, consisting of income tax expense of $15 million and after-tax interest expense of $8 million.

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

In the second quarter of 2017, Exelon amended its agreement with ComEd to also hold ComEd harmless for the unfavorable impacts on its equity from the additional income tax amounts owed by ComEd as a result of the IRS's finalization of its computation related to the like-kind exchange position. Accordingly, in the second quarter of 2017, ComEd recorded an additional receivable and non-cash equity contribution from Exelon for the total $23 million.

In order to appeal the decision, Exelon is required to pay the tax, penalties and interest at the time Exelon files its appeal (expected in the second half of 2017). Exelon expects that a payment of approximately $1.3 billion related to the like-kind exchange will be due, including $300 million from ComEd, in the second half of 2017. While Exelon will receive a tax benefit of approximately $350 million associated with the deduction for the interest, Exelon currently has a net operating loss carryforward and thus does not expect to realize the cash benefit until 2018. After taking into account these interest deduction tax benefits, the total estimated net cash outflow for the like-kind exchange is approximately $950 million, of which approximately $300 million is attributable to ComEd after giving consideration to Exelon's agreement to hold ComEd harmless from any unfavorable impacts on ComEd's equity from the like-kind exchange position. Upon a final appellate decision, which could take up to several years, Exelon expects to receive approximately $60 million related to final interest computations.

Of the above amounts payable, Exelon deposited with the IRS $1.25 billion in October of 2016. The remaining amount will be paid in the second half of 2017 at the time Exelon files its appeal of the Tax Court decision. Exelon funded the $1.25 billion deposit with a combination of cash on hand and short-term borrowings. The deposit is reflected as a current asset and the related liabilities for the tax, penalty, and interest are included on Exelon's balance sheet as current obligations.

As of June 30, 2017, ComEd has a total receivable from Exelon pursuant to the hold harmless agreement of $369 million, which is included in Current Receivables from Affiliates on ComEd's Consolidated Balance Sheet. Under the agreement, Exelon will settle this receivable with ComEd no later than the time that the payments related to the like-kind exchange are due to the IRS, currently anticipated in the second half of 2017. No recovery will be sought from ComEd customers for any interest, penalty or additional income tax payment amounts resulting from the like-kind exchange tax position.

As previously disclosed, in the first quarter of 2014, Exelon entered into an agreement to terminate its investment in one of the three municipal-owned electric generation properties in exchange for a net early termination amount of $335 million. In the first quarter of 2016, Exelon terminated its interests in the remaining two municipal-owned electric generation properties in exchange for $360 million.

Long-Term Marginal State Income Tax Rate (Exelon, Generation, ComEd, and PHI)

Exelon, Generation and PHI periodically review events that may significantly impact how income is apportioned among the states and, therefore, the calculation of their respective deferred state income taxes. Events that may require Exelon, Generation and PHI to update their long-term state tax apportionment include significant changes in tax law and/or significant operational changes. Exelon and PHI's long-term marginal state income tax rate was revised in the first quarter of 2017 as a result of a statutory rate change pursuant to Exelon's marginal state income tax rate policy, resulting in the recording of a deferred state tax benefit for Exelon of $21 million, net of tax.

On July 6, 2017, Illinois enacted Senate Bill 9, which permanently increased Illinois' total corporate income tax rate from 7.75% to 9.50% effective July 1, 2017. As a result of the rate change, in the third quarter of 2017, after taking into account regulatory recovery of tax increases at Exelon, Generation and ComEd expect to record an estimated one-time increase to deferred income taxes of approximately $180 million, $15 million and $250 million, respectively. At ComEd, the increase to the Illinois deferred income tax liability will be offset by a regulatory asset. Exelon expects to record a decrease to income tax expense of approximately $70 million (net of federal taxes) and Generation expects to record an increase to income tax expense of approximately $15 million (net of federal taxes). The rate increase is not expected to have a material ongoing impact to Exelon's, Generation's and ComEd's future results of operations.

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

12. Nuclear Decommissioning (Exelon and Generation)

Nuclear Decommissioning Asset Retirement Obligations

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

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets from December 31, 2016 to June 30, 2017:

Nuclear decommissioning ARO at December 31, 2016[(a)]	$8,734
Acquisition of FitzPatrick	417
Net increase due to changes in, and timing of, estimated cash flows	103
Accretion expense	225
Costs incurred to decommission retired plants	(3)
Nuclear decommissioning ARO at June 30, 2017[(a)(b)]	$9,476

(a) Includes $12 million and $10 million for the current portion of the ARO at June 30, 2017 and December 31, 2016, respectively, which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.
(b) Includes the fair value of the FitzPatrick ARO liability as of March 31, 2017, the date of the acquisition. See Note 4 —Mergers, Acquisitions and Dispositions.

During the six months ended June 30, 2017, Generation's nuclear ARO increased by approximately $742 million. The increase is largely driven by the acquisition of FitzPatrick and the announced early retirement of TMI. The fair value of FitzPatrick's assets and liabilities, including the ARO, was determined based on significant estimates and assumptions that are judgmental in nature. The fair value of the ARO is considered an initial estimate and will be updated with inputs from a third party engineering firm with corresponding adjustments recorded by the end of 2017. For additional details on the acquisition of FitzPatrick, see Note 4 — Mergers, Acquisitions and Dispositions. Included in the $103 million net increase due to changes in, and timing of, estimated cash flows above, is $138 million associated with the May 30, 2017 announcement to early retire the TMI nuclear unit on September 30, 2019. Refer to Note 7 — Early Nuclear Plant Retirements for additional information regarding the announced early retirement of TMI. The increase in the ARO liability for TMI incorporates the early shutdown date, increases the probabilities of longer term decommissioning scenarios, and reflects an increase in the estimated costs to decommission based on updated decommissioning cost study reflecting the early retirement of the unit.

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

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generation station unit to satisfy Generation's nuclear decommissioning obligations. Generally, NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with Generation's nuclear units have been funded with amounts collected from the previous owners and their respective utility customers. PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the former PECO plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. On March 31, 2017, PECO filed its Nuclear Decommissioning Cost Adjustment (NDCA) with the PAPUC proposing an annual recovery from customers of approximately $4 million which, if approved by the PAPUC, will be effective January 1, 2018. This amount reflects a decrease from the current approved annual collection of approximately $24 million primarily due to the removal of the collections for Limerick Units 1 and 2 as a result of the NRC approving the extension of the operating licenses for an additional 20 years. See Note 16 — Asset Retirement Obligations of Exelon's 2016 Form 10-K, for information regarding the amount collected from PECO ratepayers for decommissioning costs.

At June 30, 2017 and December 31, 2016, Exelon and Generation had NDT fund investments totaling $12,641 million and $11,061 million, respectively. The increase is primarily driven by the acquisition of FitzPatrick.

The following table provides unrealized gains on NDT funds for the three and six months ended June 30, 2017 and 2016:

	Exelon and Generation		Exelon and Generation	
	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Net unrealized gains (losses) on decommissioning trust funds — Regulatory Agreement Units[(a)]	$ (13)	$ 52	$ 210	$ 131
Net unrealized gains on decommissioning trust funds — Non-Regulatory Agreement Units[(b)(c)]	70	48	235	100

(a) Net unrealized gains (losses) related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets and Noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
(b) Excludes $(2) million and $1 million of net unrealized gains (losses) related to the Zion Station pledged assets for the three months ended June 30, 2017 and 2016 respectively. Excludes $(2) million and $3 million of net unrealized gains (losses) related to the Zion Station pledged assets for the six months ended June 30, 2017 and 2016, respectively. Net unrealized gains (losses) related to Zion Station pledged assets are included in Other current liabilities and Payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets in 2017 and 2016, respectively.
(c) Net unrealized gains related to Generation's NDT funds with Non-Regulatory Agreement Units are included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

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

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units are eliminated within Other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

Refer to Note 3 — Regulatory Matters and Note 27 — Related Party Transactions of the Exelon 2016 Form 10-K for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning

On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions, under which ZionSolutions has assumed responsibility for completing certain decommissioning activities at Zion Station, which is located in Zion, Illinois and ceased operation in 1998. See Note 16 — Asset Retirement Obligations of the Exelon 2016 Form 10-K for information regarding the specific treatment of assets, including NDT funds, and decommissioning liabilities transferred in the transaction.

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to Pledged assets for Zion Station decommissioning within Generation's and Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a Payable for Zion Station decommissioning in Generation's and Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, are recorded as a change in the Payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Generation has retained its obligation for the SNF. Following ZionSolutions' completion of its contractual obligations and transfer of the NRC license to Generation, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal, and will complete all remaining decommissioning activities associated with the SNF dry storage facility. Generation has a liability of approximately $114 million which is included within the nuclear decommissioning ARO at June 30, 2017. Generation also has retained NDT assets to fund its obligation to maintain the SNF at Zion Station until transfer to the DOE and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payables to ZionSolutions, and withdrawals by ZionSolutions at June 30, 2017 and December 31, 2016:

	Exelon and Generation	
	June 30, 2017	December 31, 2016
Carrying value of Zion Station pledged assets	$ 75	$ 113
Payable to Zion Solutions[(a)]	69	104
Current portion of payable to Zion Solutions[(b)]	69	90
Cumulative withdrawals by Zion Solutions to pay decommissioning costs[(c)]	914	878

(a) Excludes a liability recorded within Exelon's and Generation's Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT funds. The NDT funds will be utilized to satisfy the tax obligations as gains and losses are realized.

(b) Included in Other current liabilities within Exelon's and Generation's Consolidated Balance Sheets.
(c) Includes project expenses to decommission Zion Station and estimated tax payments on Zion Station NDT fund earnings.

NRC Minimum Funding Requirements

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

Generation filed its biennial decommissioning funding status report with the NRC on March 30, 2017 for all units except for Zion Station which is included in a separate report to the NRC submitted by EnergySolutions (see Zion Station Decommissioning above). The status report demonstrated adequate decommissioning funding assurance for all units except for Peach Bottom Unit 1. As a former PECO plant, financial assurance for decommissioning Peach Bottom Unit 1 is provided by the NDT fund in addition to collections from PECO ratepayers. As discussed under Nuclear Decommissioning Trust Fund Investments above, the amount collected from PECO ratepayers has been adjusted in the March 31, 2017 filing to the PAPUC which, if approved by the PAPUC, will be effective January 1, 2018.

Generation will file its next decommissioning funding status report with the NRC by March 31, 2018 for shutdown reactors and reactors within five years of shutdown. This report will reflect the status of decommissioning funding assurance as of December 31, 2017 and will include the impact of the announced early retirement of TMI. A shortfall could require Exelon to post parental guarantee for Generation's share of the funding assurance. However, the amount of any required guarantee will ultimately depend on the decommissioning approach adopted at TMI, the associated level of costs, and the decommissioning trust fund investment performance going forward.

13. Retirement Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all employees.

Effective March 31, 2017, in connection with the acquisition of FitzPatrick, Exelon established a new qualified pension plan and a new other postretirement employee benefit plan, and recorded benefit plan obligations of $38 million and $11 million, respectively. Refer to Note 4 — Mergers, Acquisitions and Dispositions for additional discussion of the acquisition of FitzPatrick.

Effective March 23, 2016, Exelon became the sponsor of all of PHI's defined benefit pension and other postretirement benefit plans, and assumed PHI's benefit plan obligations and related assets. As a result, PHI's benefit plan net obligation and related regulatory assets were transferred to Exelon.

Defined Benefit Pension and Other Postretirement Benefits

During the first quarter of 2017, Exelon received an updated valuation of its pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2017. This valuation resulted in an increase to the pension obligation of $92 million and an increase to the other postretirement benefit obligation of $57 million. Additionally, accumulated other comprehensive loss increased by approximately $59 million (after tax), regulatory assets increased by approximately $57 million and regulatory liabilities increased by approximately $4 million.

The majority of the 2017 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 4.04%. The majority of the 2017 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.58% for funded plans and a discount rate of 4.04%.

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

A portion of the net periodic benefit cost for all plans is capitalized within the Consolidated Balance Sheets. The following tables present the components of Exelon's net periodic benefit costs, prior to capitalization, for the three and six months ended June 30, 2017 and 2016 and PHI's net periodic benefit costs, prior to capitalization, for the predecessor period of January 1, 2016 to March 23, 2016.

	Pension Benefits Three Months Ended June 30,		Other Postretirement Benefits Three Months Ended June 30,	
	2017[(a)]	2016[(b)]	2017[(a)]	2016[(b)]
Components of net periodic benefit cost:				
Service cost	$ 97	$ 91	$ 28	$ 28
Interest cost	211	212	46	48
Expected return on assets	(299)	(292)	(41)	(42)
Amortization of:				
Prior service cost (benefit)	1	4	(47)	(47)
Actuarial loss	150	142	15	16
Settlement charges	2	—	—	—
Net periodic benefit cost	$ 162	$ 157	$ 1	$ 3

	Pension Benefits Six Months Ended June 30,		Other Postretirement Benefits Six Months Ended June 30,	
	2017[(a)]	2016[(b)]	2017[(a)]	2016[(b)]
Components of net periodic benefit cost:				
Service cost	$ 191	$ 170	$ 54	$ 54
Interest cost	422	403	91	90
Expected return on assets	(598)	(555)	(82)	(80)
Amortization of:				
Prior service cost (benefit)	1	7	(94)	(91)
Actuarial loss	302	269	31	30
Settlement charges	2	—	—	—
Net periodic benefit cost	$ 320	$ 294	$ —	$ 3

(a) FitzPatrick net benefit costs are included for the period after acquisition.
(b) PHI net periodic benefit costs for the period prior to the merger are not included in the table above.

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

	Predecessor PHI Pension Benefits January 1, 2016 to March 23, 2016	*Predecessor* PHI Other Postretirement Benefits January 1, 2016 to March 23, 2016
Components of net periodic benefit cost:		
Service cost	$ 12	$ 1
Interest cost	26	6
Expected return on assets	(30)	(5)
Amortization of:		
Prior service cost (benefit)	—	(3)
Actuarial loss	14	2
Net periodic benefit cost	$ 22	$ 1

The amounts below represent Exelon's, Generation's, ComEd's, PECO's, BGE's, PHI's, Pepco's, DPL's, ACE's, BSC's and PHISCO's allocated portion of the pension and postretirement benefit plan costs, which were included in Property, plant and equipment within the respective Consolidated Balance Sheets and Operating and maintenance expense within the Consolidated Statement of Operations and Comprehensive Income during the three and six months ended June 30, 2017 and 2016 and PHI's for the predecessor and successor periods of January 1, 2016 to March 23, 2016 and March 24, 2016 to June 30, 2016, respectively.

Pension and Other Postretirement Benefit Costs	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Exelon	$ 163	$ 160	$ 320	$ 297
Generation[(c)]	59	55	113	109
ComEd	44	42	87	83
PECO	7	8	14	17
BGE	16	18	32	33
BSC[(a)]	13	10	26	24
Pepco[(b)]	6	7	13	16
DPL[(b)]	3	4	6	9
ACE[(b)]	3	4	7	8
PHISCO[(a)(b)]	12	12	22	21

Pension and Other Postretirement Benefit Costs	*Successor* Three Months Ended June 30, 2017	*Successor* Three Months Ended June 30, 2016	*Successor* Six Months Ended June 30, 2017	*Successor* March 24, 2016 to June 30, 2016	*Predecessor* January 1, 2016 to March 23, 2016
PHI	$ 24	$ 27	$ 48	$ 31	$ 23

(a) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO, BGE, PHI, Pepco, DPL or ACE amounts above.
(b) Pepco's, DPL's, ACE's and PHISCO's pension and postretirement benefit costs for the six months ended June 30, 2016 include $7 million, $4 million, $3 million and $9 million, respectively, of costs incurred prior to the closing of Exelon's merger with PHI on March 23, 2016.
(c) FitzPatrick net benefit costs are included for the period after acquisition.

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

Defined Contribution Savings Plans

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the three and six months ended June 30, 2017 and 2016 and PHI's for the predecessor and successor periods of January 1, 2016 to March 23, 2016 and March 24, 2016 to June 30, 2016, respectively.

Savings Plan Matching Contributions	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Exelon	$ 33	$ 30	$ 63	$ 56
Generation	14	13	28	25
ComEd	8	7	15	13
PECO	2	2	4	4
BGE	3	2	4	3
BSC[(a)]	3	2	5	7
Pepco[(b)]	1	1	2	2
DPL[(b)]	1	—	1	1
PHISCO[(a)(b)]	1	2	3	3
ACE	—	1	1	1

Savings Plan Matching Contributions	*Successor* Three Months Ended June 30, 2017	*Successor* Three Months Ended June 30, 2016	*Successor* Six Months Ended June 30, 2017	*Successor* March 24, 2016 to June 30, 2016	*Predecessor* January 1, 2016 to March 23, 2016
PHI	$ 3	$ 4	$ 7	$ 4	$ 3

(a) These amounts primarily represent amounts billed to Exelon and PHI's subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO, BGE, Pepco and DPL amounts above.
(b) Pepco's, DPL's and PHISCO's matching contributions for the six months ended June 30, 2016 include $1 million, $1 million and $1 million, respectively, of costs incurred prior to the closing of Exelon's merger with PHI on March 23, 2016, which is not included in Exelon's matching contributions for the six months ended June 30, 2016.

14. Severance (All Registrants)

The Registrants have an ongoing severance plan under which, in general, the longer an employee worked prior to termination the greater the amount of severance benefits. The Registrants record a liability and expense or regulatory asset for severance once terminations are probable of occurrence and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan ("one-time termination benefits"), the Registrants measure the obligation and record the expense at fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

Ongoing Severance Plans

The Registrants provide severance and health and welfare benefits under Exelon's ongoing severance benefit plans to terminated employees in the normal course of business. These benefits are accrued for when the benefits are considered probable and can be reasonably estimated.

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

For the three and six months ended June 30, 2017 and 2016, Exelon, Generation, ComEd, PHI, Pepco, DPL, and ACE recorded the following severance costs associated with these ongoing severance benefits within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income.

	Exelon	Generation[(a)]	ComEd[(a)]	Successor PHI	Pepco[(a)]	DPL[(a)]	ACE[(a)]
Three Months Ended							
June 30, 2017	$ 5	$ 1	$ 1	$ 3	$ 1	$ 1	$ 1
June 30, 2016	2	1	1	—	—	—	—
Six Months Ended							
June 30, 2017	$ 9	$ 4	$ 2	$ 3	$ 1	$ 1	$ 1
June 30, 2016	4	3	1	—	—	—	—

(a) The amounts above for Generation include less than $1 million and $1 million for amounts billed by BSC through intercompany allocations for the three and six months ended June 30, 2017, respectively, and $1 million and $2 million for the three and six months ended June 30, 2016, respectively. The amounts above for ComEd include less than $1 million and $1 million for amounts billed by BSC through intercompany allocations for the three and six months ended June 30, 2017, respectively, and less than $1 million and $1 million for the three and six months ended June 30, 2016, respectively. Amounts billed by PHISCO to Pepco, DPL and ACE were $1 million, each, for both three and six months ended June 30, 2017. Pepco, DPL and ACE did not have any ongoing severance plans for the three and six months ended June 30, 2016.

Cost Management Program-Related Severance

In August 2015, Exelon announced a cost management program focused on cost savings at BSC and Generation, including the elimination of approximately 500 positions. 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. Exelon expects that approximately 250 corporate support positions in BSC and approximately 250 positions located throughout Generation will be eliminated.

For the three months ended June 30, 2017 and 2016, the amounts for severance costs related to the cost management program were immaterial. For the six months ended June 30, 2017 and 2016, the Registrants recorded the following severance costs related to the cost management program within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income, pursuant to the authoritative guidance for ongoing severance plans:

	Exelon	Generation	ComEd	PECO	BGE
Six Months Ended					
June 30, 2017[(a)]	$ (1)	$ (1)	$ —	$ —	$ —
June 30, 2016[(b)]	$ 17	$ 12	$ 3	$ 1	$ 1

(a) Amounts billed by BSC through intercompany allocations for the six months ended June 30, 2017 were immaterial.
(b) The amounts above for Generation, ComEd, PECO and BGE include $7 million, $3 million, $1 million and $1 million, respectively, for amounts billed by BSC through intercompany allocations for the six months ended June 30, 2016.

Early Plant Retirement-Related Severance (Exelon and Generation)

As a result of the Three Mile Island plant retirement decision, Exelon and Generation will incur certain employee-related costs, including severance benefit costs. Severance costs will be provided to management employees that are eligible under Exelon's severance policy, to the extent that those employees are not redeployed to other locations. In June 2017, Exelon and Generation recognized severance costs of $17 million related to expected management employee severances resulting from the plant retirements within Operating and maintenance expense in their Consolidated Statements of Operation and Comprehensive Income. Approximately half of the employees at this location fall under a collective bargaining union agreement and are not eligible for severance benefits under an existing plan. The union and Exelon will negotiate terms of any severance benefits. If severance benefits are successfully negotiated, the amounts will be accrued as a one-time employee termination benefit once the established plan is communicated to employees. The final amount of the severance cost will ultimately depend on the specific employees severed. See Note — 7 Early Nuclear Plant Retirements for additional information regarding the announced early retirement of TMI.

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

Severance Costs Related to the PHI Merger

Upon closing the PHI Merger, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. Cash payments under the plan began in May 2016 and will continue through 2020.

Pepco and DPL maintain regulatory assets for merger related integration costs which include a portion of the severance costs related to the PHI merger that is either currently being recovered in rates or is deemed probable of recovery if not currently being recovered in rates. As of June 30, 2017 and 2016, Pepco and DPL have regulatory assets of $12 million and $13 million, respectively, and $9 million and $3 million, respectively.

For the three and six months ended June 30, 2017, the PHI merger severance costs were immaterial. For the three and six months ended June 30, 2016, the Registrants recorded the following severance costs associated with the identified job reductions within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income, pursuant to the authoritative guidance for ongoing severance plans:

	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Three Months Ended June 30, 2016									
Severance costs (benefits)[(a)]	$ 2	$ (1)	$ (1)	$ —	$ —	$ 4	$ 2	$ 1	$ 1
Six Months Ended June 30, 2016									
Severance costs[(a)]	$ 55	$ 9	$ 2	$ 1	$ 1	$ 42	$ 20	$12	$ 10

(a) The amounts above for Generation, ComEd, PECO, BGE, Pepco, DPL and ACE include $(1) million, $(1) million, less than $1 million, less than $1 million, $2 million, $1 million and $1 million, respectively, for amounts billed by BSC and/or PHISCO through intercompany allocations for the three months ended June 30, 2016, and $8 million, $2 million, $1 million, $1 million, $19 million, $11 million and $10 million for the six months ended June 30, 2016.

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

Severance Liability

Amounts included in the table below represent the severance liability recorded for the severance plans above for employees of each Registrant and exclude amounts included at Exelon and billed through intercompany allocations:

Severance Liability	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Balance at December 31, 2016	$ 88	$ 36	$ 3	$ —	$—	$ 29	$ —	$—	$—
Severance charges[a]	25	17	1	—	—	3	—	—	—
Payments	(18)	(4)	(1)	—	—	(10)	—	—	—
Balance at June 30, 2017	$ 95	$ 49	$ 3	$ —	$—	$ 22	$ —	$—	$—

(a) Includes salary continuance and health and welfare severance benefits.

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

The following tables present changes in accumulated other comprehensive income (loss) (AOCI) by component for the six months ended June 30, 2017 and 2016:

Six Months Ended June 30, 2017	Gains and (losses) on Cash Flow Hedges	Unrealized Gains and (losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon[a]						
Beginning balance	$ (17)	$ 4	$ (2,610)	$ (30)	$ (7)	$(2,660)
OCI before reclassifications	1	2	(58)	3	5	(47)
Amounts reclassified from AOCI[b]	4	—	70	—	—	74
Net current-period OCI	5	2	12	3	5	27
Ending balance	$ (12)	$ 6	$ (2,598)	$ (27)	$ (2)	$(2,633)
Generation[a]						
Beginning balance	$ (19)	$ 2	$ —	$ (30)	$ (7)	$ (54)
OCI before reclassifications	1	—	—	3	6	10
Amounts reclassified from AOCI[b]	4	—	—	—	—	4
Net current-period OCI	5	—	—	3	6	14
Ending balance	$ (14)	$ 2	$ —	$ (27)	$ (1)	$ (40)
PECO[a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI[b]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1

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

Six Months Ended June 30, 2016	Gains and (losses) on Cash Flow Hedges	Unrealized Gains and (losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon[a]						
Beginning balance	$ (19)	$ 3	$ (2,565)	$ (40)	$ (3)	$(2,624)
OCI before reclassifications	(10)	—	(2)	6	(7)	(13)
Amounts reclassified from AOCI[b]	3	—	69	—	—	72
Net current-period OCI	(7)	—	67	6	(7)	59
Ending balance	$ (26)	$ 3	$ (2,498)	$ (34)	$ (10)	$(2,565)
Generation[a]						
Beginning balance	$ (21)	$ 1	$ —	$ (40)	$ (3)	$ (63)
OCI before reclassifications	(7)	—	—	6	(4)	(5)
Amounts reclassified from AOCI[b]	3	—	—	—	—	3
Net current-period OCI	(4)	—	—	6	(4)	(2)
Ending balance	$ (25)	$ 1	$ —	$ (34)	$ (7)	$ (65)
PECO[a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI[b]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1
PHI Predecessor[a]						
Beginning balance January 1, 2016	$ (8)	$ —	$ (28)	$ —	$ —	$ (36)
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI[b]	—	—	1	—	—	1
Net current-period OCI	—	—	1	—	—	1
Ending balance March 23, 2016[c]	$ (8)	$ —	$ (27)	$ —	$ —	$ (35)

(a) All amounts are net of tax and noncontrolling interest. Amounts in parenthesis represent a decrease in AOCI.
(b) See next tables for details about these reclassifications.
(c) As a result of the PHI Merger, the PHI predecessor balances at March 23, 2016 were reduced to zero on March 24, 2016 due to purchase accounting adjustments applied to PHI.

ComEd, PECO, BGE, Pepco, DPL and ACE did not have any reclassifications out of AOCI to Net income during the three and six months ended June 30, 2017 and 2016. The following tables present amounts reclassified out of AOCI to Net income for Exelon, Generation and PHI during the three and six months ended June 30, 2017 and 2016.

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

Three Months Ended June 30, 2017

Details about AOCI components	Items reclassified out of AOCI[a] Exelon	Generation	Affected line item in the Statement of Operations and Comprehensive Income
Gains (losses) on cash flow hedges			
Other cash flow hedges	$ —	$ —	Interest expense
Total before tax	—	—	
Tax benefit	—	—	
Net of tax	$ —	$ —	Comprehensive income
Amortization of pension and other postretirement benefit plan items			
Prior service costs[b]	$ 23	$ —	
Actuarial losses[b]	(81)	—	
Total before tax	(58)	—	
Tax benefit	24	—	
Net of tax	$ (34)	$ —	
Total Reclassifications for the period	$ (34)	$ —	Comprehensive income

Six Months Ended June 30, 2017

Details about AOCI components	Items reclassified out of AOCI[a] Exelon	Generation	Affected line item in the Statement of Operations and Comprehensive Income
Gains and (losses) on cash flow hedges			
Other cash flow hedges	$ (7)	$ (7)	Interest expense
Total before tax	(7)	(7)	
Tax benefit	3	3	
Net of tax	$ (4)	$ (4)	Comprehensive income
Amortization of pension and other postretirement benefit plan items			
Prior service costs[b]	$ 46	$ —	
Actuarial losses[b]	(162)	—	
Total before tax	(116)	—	
Tax benefit	46	—	
Net of tax	$ (70)	$ —	
Total Reclassifications	$ (74)	$ (4)	Comprehensive income

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

Three Months Ended June 30, 2016

Details about AOCI components	Items reclassified out of AOCI[a] Exelon	Generation	Affected line item in the Statement of Operations and Comprehensive Income
Amortization of pension and other postretirement benefit plan items			
Prior service costs[b]	$ 19	$ —	
Actuarial losses[b]	(75)	—	
Total before tax	(56)	—	
Tax benefit	22	—	
Net of tax	$ (34)	$ —	
Total Reclassifications for the period	$ (34)	$ —	Comprehensive income

Six Months Ended June 30, 2016

Details about AOCI components	Items reclassified out of AOCI[a] Exelon	Generation	*Predecessor* PHI	Affected line item in the Statement of Operations and Comprehensive Income
Gains and (losses) on cash flow hedges				
Other cash flow hedges	$ (5)	$ (5)	—	Interest expense
Total before tax	(5)	(5)	—	
Tax benefit	2	2	—	
Net of tax	$ (3)	$ (3)	$ —	Comprehensive income
Amortization of pension and other postretirement benefit plan items				
Prior service costs[b]	$ 38	$ —	$ —	
Actuarial losses[b]	(151)	—	(1)	
Total before tax	(113)	—	(1)	
Tax benefit	44	—	—	
Net of tax	$ (69)	$ —	$ (1)	
Total Reclassifications	$ (72)	$ (3)	$ (1)	Comprehensive income

(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 13 — Retirement Benefits for additional details).

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

The following table presents income tax expense (benefit) allocated to each component of other comprehensive income (loss) during the three and six months ended June 30, 2017 and 2016:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Exelon				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	$ 9	$ 7	$ 18	$ 15
Actuarial loss reclassified to periodic benefit cost	(32)	(30)	(64)	(60)
Pension and non-pension postretirement benefit plans valuation adjustment	1	—	3	1
Change in unrealized (loss)/gain on cash flow hedges	(2)	2	(3)	4
Change in unrealized (loss)/gain on equity investments	—	1	(3)	3
Change in unrealized (loss)/gain on marketable securities	—	(1)	(1)	—
Total	$ (24)	$ (21)	$ (50)	$ (37)
Generation				
Change in unrealized (loss)/gain on cash flow hedges	$ (2)	$ 1	$ (3)	$ 3
Change in unrealized (loss)/gain on equity investments	—	1	(2)	3
Total	$ (2)	$ 2	$ (5)	$ 6

PHI	*Predecessor* January 1, 2016 to March 23, 2016
Pension and non-pension postretirement benefit plans:	
Actuarial loss reclassified to periodic cost	$ —

16. Earnings Per Share and Equity (Exelon)

Earnings per Share

Diluted earnings per share is calculated by dividing Net income attributable to common shareholders by the weighted average number of shares of common stock outstanding, including shares to be issued upon exercise of stock options, performance share awards and restricted stock outstanding under Exelon’s LTIPs considered to be common stock equivalents. The following table sets forth the components of basic and diluted earnings per share and shows the effect of these stock options, performance share awards and restricted stock on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Exelon				
Net income attributable to common shareholders	$ 80	$ 267	$ 1,076	$ 440
Weighted average common shares outstanding — basic	934	924	931	923
Assumed exercise and/or distributions of stock-based awards	2	2	1	3
Weighted average common shares outstanding — diluted	936	926	932	926

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 8 million and 9 million for the three and six months ended June 30, 2017, respectively, and 11 million and 12 million for the three and six months ended June 30, 2016, respectively. There were no equity units related to the PHI Merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect for the three and six months ended June 30, 2017. The number of equity units related to the PHI Merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect was under 1 million and 2 million for the three and six months ended June 30, 2016. Refer to Note 20 — Shareholders' Equity of the Exelon 2016 Form 10-K for further information regarding the equity units.

On June 1, 2017, Exelon settled the forward purchase contract, which was a component of the June 2014 equity units, through the issuance of approximately 33 million shares of Exelon common stock from treasury stock. The issuance of shares on June 1, 2017, triggered full dilution in the EPS calculation, which prior to settlement were included in the calculation of diluted EPS using the treasury stock method.

Prior to the June 2017 issuance Exelon had approximately 35 million shares of treasury stock with a cost of $2.3 billion. After issuance, Exelon has approximately 2 million shares of Treasury stock remaining, at a historical cost of $123 million. In 2008, Exelon management decided to defer indefinitely any share repurchases.

17. Commitments and Contingencies (*All Registrants*)

The following is an update to the current status of commitments and contingencies set forth in Note 24 of the Exelon 2016 Form 10-K . See Note 4 — Mergers, Acquisitions and Dispositions for further discussion on the PHI Merger commitments.

Commitments

Constellation Merger Commitments (Exelon and Generation)

In February 2012, the MDPSC issued an Order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion.

The direct investment includes the construction of a new 21-story headquarters building in Baltimore for Generation's competitive energy business that was substantially complete in November 2016 and is now occupied by approximately 1,500 Exelon employees. Generation's investment includes leasehold improvements that are not expected to exceed $110 million. In addition, Generation entered into a 20 year operating lease as the primary lessee of the building. Refer to Note 24 — Commitments and Contingencies of the Combined Notes to the Consolidated Financial Statements in the Exelon 2016 Form 10-K for additional information regarding Generation's future minimum lease payments.

The direct investment commitment also includes $450 million to $500 million relating to Exelon and Generation's development or assistance in the development of 285 — 300 MWs of new generation in Maryland, which is expected to be completed within a period of 10 years. The MDPSC order contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed or certain specified provisions are elected, making liquidated damages payments. Exelon and Generation have incurred $457 million towards satisfying the commitment for new generation development in the state of

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Maryland, with approximately 220 MW of the new generation commencing with commercial operations to date and an additional 10 MW commitment satisfied through a liquidated damages payment made in the fourth quarter of 2016. Additionally, during the fourth quarter of 2016, given continued declines in projected energy and capacity prices, Generation terminated rights to certain development projects originally intended to meet its remaining 55MW commitment amount. The commitment will now most likely be satisfied via payment of liquidated damages or execution of a third party PPA, rather than by Generation constructing renewable generating assets. As a result, Exelon and Generation recorded a pre-tax $50 million loss contingency in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2016.

Equity Investment Commitments (Exelon and Generation)

As part of Generation's recent investments in technology development, Generation enters into equity purchase agreements that include commitments to invest additional equity through incremental payments to fund the anticipated needs of the planned operations of the associated companies. As of June 30, 2017, Generation's estimated commitments relating to its equity purchase agreements, including the in-kind services contributions, is anticipated to be as follows:

	Total
2017 (remainder of year)	$ 8
2018	7
2019	3
Total	$ 18

Commercial Commitments (All Registrants)

The Registrants' commercial commitments as of June 30, 2017 , representing commitments potentially triggered by future events were as follows:

	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Letters of credit (non-debt)[(a)]	$1,326	$ 1,243	$ 14	$ 23	$ 2	$ 1	$ 1	$—	$—
Surety bonds[(b)]	1,113	1,014	12	18	11	21	13	4	4
Financing trust guarantees	628	—	200	178	250	—	—	—	—
Guaranteed lease residual values[(c)]	19	—	—	—	—	19	6	7	5
Total commercial commitments	$3,086	$ 2,257	$ 226	$219	$263	$ 41	$ 20	$11	$ 9

(a) Letters of credit (non-debt) — Exelon and certain subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds — Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) 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 $48 million, $14 million of which is a guarantee by Pepco, $18 million by DPL and $13 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, including the CENG 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 June 30, 2017 , the current liability limit per incident is $13.4 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors at least once every five years with the last adjustment effective September 10, 2013. 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 $13.0 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 $2.8 billion, including CENG's related liability, however any amounts payable under this secondary layer would be capped at $420 million per year.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.4 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 5 — Investment in Constellation Energy Nuclear Group, LLC of the Exelon 2016 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.

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 $360 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 liquidity.

Environmental Issues *(All Registrants)*

General. The Registrants' operations have in the past, and may in the future, require substantial expenditures in order 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.

ComEd, PECO, BGE and DPL have identified sites where former MGP 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, 19 of which the remediation has been completed and approved by the Illinois EPA or the U.S. EPA and 23 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 2021.
- PECO has identified 26 sites, 17 of which have been remediated in accordance with applicable PA DEP regulatory requirements. The remaining 9 sites 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 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor's acquisition. Two of the gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. In May 2017, BGE completed the additional work requested by MDE. All the sample testing produced results that were below the cleanup action level established by MDE and no further investigation is required. For more information, see the discussion of the Riverside site below.
- DPL has identified 2 sites, all of which the remediation has been completed and approved by the MDE or the Delaware Department of Natural Resources and Environmental Control.

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. ComEd and PECO have recorded regulatory assets for the recovery of these costs. See Note 5 — Regulatory Matters for additional information regarding the associated regulatory assets. BGE is authorized to recover, and is currently recovering, environmental costs for the remediation of the former MGP facility sites from customers; however, while BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. DPL has historically received recovery of actual clean-up costs in distribution rates.

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

As of June 30, 2017 and December 31, 2016, 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:

June 30, 2017	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 412	$ 315
Generation	67	—
ComEd	284	282
PECO	32	31
BGE	3	2
PHI (Successor)	26	—
Pepco	23	—
DPL	2	—
ACE	1	—

December 31, 2016	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 429	$ 325
Generation	72	—
ComEd	292	291
PECO	33	31
BGE	2	2
PHI (Successor)	30	1
Pepco	27	—
DPL	2	1
ACE	1	—

The historical nature of the MGP 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.

The Registrants cannot reasonably estimate whether they will incur other 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.

Water Quality

Benning Road Site NPDES Permit Limit Exceedances. Pepco holds an NPDES permit issued by EPA with a July 19, 2009 effective date, which authorizes discharges from the Benning Road service facility. The 2009 permit for the first time imposed numerical limits on the allowable concentration of certain metals in storm water discharged from the site into the Anacostia River. The permit contemplated that Pepco would meet these limits over time through the use of best management practices (BMPs). The BMPs were effective in reducing metal concentrations in storm water discharges, but were not sufficient to meet all of the numerical limits for all metals.

The 2009 permit remains in effect pending EPA's action on the Pepco renewal application, including resolution of the stormwater compliance issues. On October 30, 2015, EPA filed a Clean Water Act civil enforcement action against Pepco in federal district court, and in March 2016 the court granted a motion by the Anacostia Riverkeeper to intervene in this case as a plaintiff along with EPA. Since 2009 Pepco has installed runoff mitigation measures and implemented new operating procedures to comply with regulations. In January 2017, the parties agreed to a settlement in the form of a Consent Decree whereby Pepco will pay a civil penalty in the amount of $1.6 million, continue the BMPs to manage stormwater, construct a new stormwater treatment system, and make certain other capital improvements to the stormwater management system. On May 19, 2017, the Consent Decree was entered with the Court and became final. The Civil Penalty assessed under the Consent Decree of $1.6 million was paid on June 5, 2017 and other requirements of the Decree are now being implemented.

Solid and Hazardous Waste

Cotter Corporation. 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. On May 29, 2008, the EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. The current estimated cost of the landfill cover remediation for the site is approximately $90 million, including escalation, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability, which is included in the table above. By letter dated January 11, 2010, the EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the supplemental feasibility study to the EPA for review. Since June 2012, the EPA has requested that the PRPs perform a series of additional analyses and groundwater and soil sampling as part of the supplemental feasibility study, that were completed in December 2016. The EPA has advised the PRPs that the EPA announcement of the proposed remedy will take place in the first quarter of 2018. Thereafter, the EPA will select a final remedy and seek to enter into a Consent Decree with the PRPs to effectuate the remedy. Recent investigation has identified a number of other parties who may be PRPs and could be liable to contribute to the final remedy. Further investigation is underway. Generation believes that a partial excavation remedy is reasonably possible, and the partial excavation costs, inclusive of a landfill cover, could range from approximately $225 million to $650 million; such costs would likely be shared by the final group of identified PRPs. Generation believes the likelihood that the EPA would require a complete excavation remedy is remote. The cost of a partial or complete excavation could have a material, unfavorable impact on Generation's and Exelon's future results of operations and cash flows.

During December 2015, the EPA took two actions related to the West Lake Landfill designed to abate what it termed as imminent and dangerous conditions at the landfill. The first involved installation by the PRPs of a non-combustible surface cover to protect against surface fires in areas where radiological materials are believed to have been disposed. Generation has accrued what it believes to be an adequate amount to cover its anticipated liability for this interim action. The second action involved EPA's public statement that it will require the PRPs to construct a barrier wall in an adjacent landfill to prevent a subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, EPA has not provided sufficient details related to the basis for and the requirements and design of a barrier wall to enable Generation to determine the likelihood such a remedy will ultimately be implemented, assess the degree to which Generation may have liability as a potentially responsible party, or develop a reasonable estimate of the potential incremental costs. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Generation's and Exelon's future results of operations and cash flows. Finally, one of the other PRPs, the landfill owner and operator of the adjacent landfill, has indicated that 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, Generation and Exelon do not possess sufficient information to assess this claim and are therefore unable to determine the impact on their future results of operations and cash flows.

On February 2, 2016, the U.S. Senate passed a bill to transfer remediation authority over the West Lake Landfill from the EPA to the U.S. Army Corps of Engineers, under the Formerly Utilized Sites Remedial Action Program (FUSRAP). The legislation was not passed in the U.S. House of Representatives, and would therefore require reintroduction in the Senate for consideration in the current session of Congress. Should such proposed legislation ultimately become law, it would be subject to annual funding appropriations in the U.S. Budget. Remediation under FUSRAP would not alter the liability of the PRPs, but would likely delay the determination of a final remedy and its implementation.

On August 8, 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 the 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. The DOJ and the PRPs agreed to toll the statute of limitations until August 2018 so that settlement discussions could proceed. Based on Generation's preliminary review, it appears probable that Generation has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this 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. The complaints do not contain specific damage claims. In the event of a finding of liability against Cotter, it is reasonably possible that Exelon would be financially responsible due to its indemnification responsibilities of Cotter described above. The court has dismissed a number of lawsuits, and is expected to dismiss additional lawsuits based on a recent ruling. Pre-trial motions and discovery are proceeding in the remaining cases and a pre-trial scheduling order has been filed with the court. At this stage of the litigation, Generation and ComEd cannot estimate a range of loss, if any.

68th Street Dump. In 1999, the EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In connection with BGE's 2000 corporate restructuring the responsibility for this liability was transferred to Constellation and as a result of the 2012 Exelon and CEG merger is now Generation's responsibility. In March 2004, the PRPs formed the 68th Street Coalition and entered into consent order negotiations with the U.S. EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the U.S. EPA and the PRPs with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The PRPs submitted their investigation of the range of clean-up options in the first quarter of 2011. On September 30, 2013, EPA issued the Record of Decision identifying its preferred remedial alternative for the site. The estimated cost for the alternative chosen by EPA is consistent with the PRPs estimated range of costs noted above. In July, 2017 the PRPs and EPA finalized the terms of a Consent Decree which is being executed by the Parties and will then be lodged with the Court and subject to a 30-day public comment period after which it is anticipated it will be approved by the Court without any significant change in the costs for cleanup. There will also be an ancillary agreement between the PRP's who will be performing the remedy and those who have elected to enter into cash settlements and become non-performing parties. Generation has elected to be a non-performing party and the settlement terms will provide contribution and all other protections against the performing parties. Generation has reached a preliminary settlement agreement for its share of the estimated clean-up costs, which is included in the table above and is immaterial to the Generation and Exelon financial statements.

Rossville Ash Site. The Rossville Ash Site is a 32-acre property located in Rosedale, Baltimore County, Maryland, which was used for the placement of fly ash from 1983-2007. The property is owned by Constellation Power Source Generation, LLC (CPSG), a wholly owned subsidiary of Generation. In 2008, CPSG investigated and remediated the property by entering it into the Maryland Voluntary Cleanup Program (VCP) to address any historic environmental concerns and ready the site for appropriate future redevelopment. The site was accepted into the program in 2010 and is currently going through the process to remediate the site and receive closure from MDE. Exelon currently estimates the cost to close the site to be approximately $2 million which has been fully reserved and included in the table above as of June 30, 2017.

Sauer Dump. On May 30, 2012, BGE was notified by the U.S. EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, Maryland. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. In addition, the U.S. EPA is seeking recovery from the PRPs of $1.7 million for past cleanup and investigation costs at the site. On March 11, 2013, BGE and three other PRPs signed an Administrative Settlement Agreement and Order on Consent with the U.S. EPA which requires the PRPs to conduct a remedial investigation and feasibility study at the site to determine what, if any, are the appropriate and recommended cleanup activities for the site. Although the ultimate outcome of this proceeding is uncertain based on the information complied to date, BGE has developed an estimate of the range of BGE's probable liability and has established an appropriate accrual that is included it in the table above. It is possible, however, that final resolution of this matter could have a material, unfavorable impact on BGE's future results of operations and cash flows.

Riverside. In 2013, the MDE, at the request of EPA, conducted a site inspection and limited environmental sampling of certain portions of the 170 acre Riverside property owned by BGE. The site consists of several different parcels with different current and historical uses. The sampling included soil and groundwater samples for a number of potential environmental contaminants. The sampling confirmed the existence of contaminants consistent with the known historical uses of the various portions of the site. In March 2014, the MDE requested that BGE conduct an investigation which included a site-wide investigation of soils, sediment, groundwater, and surface water to complement the MDE sampling. The field investigation was completed in January 2015, and a final report was provided to MDE in June 2015. In November 2015, MDE provided BGE with its comments and recommendations on the report which require BGE to conduct further investigation and sampling at the site to better delineate the nature and extent of historic contamination, including off-site sediment and soil sampling. MDE did not request any interim remediation at this time and in May 2017 BGE completed the additional work requested by MDE. All the sample testing produced results that were below the cleanup action level established by MDE and no further investigation is required. BGE has established what it believes is an appropriate reserve based upon the investigation to date. The established reserve is included in the table above. As the investigation and potential remediation proceed, it is possible that additional reserves could be established, in amounts that could be material to BGE.

BGE is authorized to recover, and is currently recovering, environmental costs for the remediation of the former MGP facility sites from customers; however, while BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. Additionally, legislation was passed during the 2017 Maryland General Assembly session that should further support BGE’s recovery of its clean-up costs.

Benning Road Site. 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.

The initial RI field work began in January 2013 and was completed in December 2014. In April 2015, Pepco and Pepco Energy Services submitted a draft RI Report to DOEE. After review, DOEE determined that additional field investigation and data analysis was required to complete the RI process (much of which was beyond the scope of the original DOEE-approved RI work plan). In the meantime, Pepco and Pepco Energy Services revised the draft RI Report to address DOEE’s comments and DOEE released the draft RI Report for public review in February 2016. Once the additional RI work has been completed, Pepco and Pepco Energy Services will issue a draft “final” RI report for review and comment by DOEE and the public. Pepco and Pepco Energy Services 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 June 2018.

Upon DOEE’s approval of the final RI and FS Reports, Pepco and Pepco Energy Services 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 Pepco Energy Services have determined that a loss associated with this matter for PHI, Pepco and Pepco Energy Services is probable and an estimated liability for this issue has been accrued, which is included in the table above. As the remedial investigation proceeds and potential remedies are identified, it is possible that additional accruals could be established in amounts that could be material to PHI, Pepco and Pepco Energy Services. Pursuant to Exelon's March 2016 acquisition of PHI, Pepco Energy Services was transferred to Generation. The ultimate resolution of this matter is currently not expected to have any significant financial impact on Generation.

***Anacostia River Tidal Reach*.** Contemporaneous with the Benning RI/FS being performed by Pepco and Pepco Energy Services, 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-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 Road 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. DOEE has advised the Consultative Working Group that the federal and DOEE authorities are conducting phase 2 of a remedial investigation. DOEE has targeted June 2018 as the date for remedy selection for clean-up of sediments in this section of the river. The Consultative Working Group and the other possible PRPs have provided input into the proposed clean-up process and schedule. At this time, it is not possible to predict the extent of Pepco's participation in the river-wide RI/FS process, and Pepco cannot estimate the reasonably possible range of loss for response costs beyond those associated with the Benning RI/FS component of the river-wide initiative. It is possible, however, that resolution of this matter could have a material, unfavorable impact on Exelon's and Pepco's future results of operations and cash flows.

Conectiv Energy Wholesale Power Generation Sites. In July 2010, PHI sold the wholesale power generation business of Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries (Conectiv Energy) to Calpine Corporation (Calpine). Under New Jersey's Industrial Site Recovery Act (ISRA), the transfer of ownership to Calpine triggered an obligation on the part of Conectiv Energy to remediate any environmental contamination at each of the nine Conectiv Energy generating facility sites located in New Jersey. Under the terms of the sale, Calpine assumed responsibility for performing the ISRA-required remediation and for the payment of all related ISRA compliance costs up to $10 million. Predecessor PHI was obligated to indemnify Calpine for any ISRA compliance remediation costs in excess of $10 million. According to PHI's estimates, the costs of ISRA-required remediation activities at the 9 generating facility sites are in the range of approximately $7 million to $18 million, and predecessor PHI established an appropriate accrual for its share of the estimated clean-up costs. Pursuant to Exelon's March 2016 acquisition of PHI, the Conectiv Energy legal entity was transferred to Generation and the accrual for Predecessor PHI's share of the estimated clean-up costs was also transferred to Generation and is included in the table above as a liability of Generation. The responsibility to indemnify Calpine is shared by PHI and Generation. The ultimate resolution of this matter is currently not expected to have a material financial impact on PHI and Generation.

Rock Creek Mineral Oil Release. In late August 2015, a Pepco underground transmission line in the District of Columbia suffered a breach, resulting in the release of non-toxic mineral oil surrounding the transmission line into the surrounding soil, and a small amount reached Rock Creek through a storm drain. Pepco notified regulatory authorities, and Pepco and its spill response contractors placed booms in Rock Creek, blocked the storm drain to prevent the release of mineral oil into the creek and commenced remediation of soil around the transmission line and the Rock Creek shoreline. Pepco estimates that approximately 6,100 gallons of mineral oil were released and that its remediation efforts recovered approximately 80% of the amount released. Pepco's remediation efforts are ongoing under the direction of the DOEE, including the requirements of a February 29, 2016 compliance order which requires Pepco to prepare a full incident investigation report and prepare a removal action work plan to remove all impacted soils in the vicinity of the storm drain outfall, and in collaboration with the National Park Service, the Smithsonian Institution/National Zoo and EPA. Pepco's investigation presently indicates that the damage to Pepco's facilities occurred prior to the release of mineral oil when third-party excavators struck the Pepco underground transmission line while installing cable for another utility.

To the extent recovery is available against any party who contributed to this loss, PHI and Pepco will pursue such action. Exelon, PHI and Pepco continue to investigate the cause of the incident, the parties involved, and legal responsibility under District of Columbia law, but do not believe that the remediation costs to resolve this matter will have a material adverse effect on their respective financial condition, results of operations or cash flows.

Brandywine Fly Ash Disposal Site. In February 2013, Pepco received a letter from the MDE requesting that Pepco investigate the extent of waste on a Pepco right-of-way that traverses the Brandywine fly ash disposal site in Brandywine, Prince George's County, Maryland, owned by NRG Energy, Inc. (as successor to GenOn MD Ash Management, LLC) (NRG). In July 2013, while reserving its rights and related defenses under a 2000 agreement covering the sale of this site, Pepco indicated its willingness to investigate the extent of, and propose an appropriate closure plan to address, ash on the right-of-way. Pepco submitted a schedule for development of a closure plan to MDE on September 30, 2013 and, by letter dated October 18, 2013, MDE approved the schedule.

Exelon, PHI and Pepco have determined that a loss associated with this matter is probable and have estimated that the costs for implementation of a closure plan and cap on the site are in the range of approximately $3 million to $6 million, for which an appropriate reserve has been established and is included in the table above. Exelon, PHI and Pepco believe that the costs incurred in this matter will be recoverable from NRG under the 2000 sale agreement.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims (Exelon, Generation, ComEd, PECO and BGE)

Exelon, Generation and PECO. 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 reserve is recorded on an undiscounted basis and excludes the estimated legal costs associated with handling these matters, which could be material.

At June 30, 2017 and December 31, 2016, Generation had reserved approximately $81 million and $83 million, respectively, in total for asbestos-related bodily injury claims. As of June 30, 2017, approximately $21 million of this amount related to 224 open claims presented to Generation, while the remaining $59 million of the reserve 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 an adjustment to the reserve is necessary.

On November 22, 2013, the Supreme Court of Pennsylvania held that the Pennsylvania Workers Compensation Act does not apply to an employee's disability or death resulting from occupational disease, such as diseases related to asbestos exposure, which manifests more than 300 weeks after the employee's last employment-based exposure, and that therefore the exclusivity provision of the Act does not preclude such employee from suing his or her employer in court. The Supreme Court's ruling reverses previous rulings by the Pennsylvania Superior Court precluding current and former employees from suing their employers in court, despite the fact that the same employee was not eligible for workers compensation benefits for diseases that manifest more than 300 weeks after the employee's last employment-based exposure to asbestos. Since the Pennsylvania Supreme Court's ruling in November 2013, Exelon, Generation, and PECO have experienced an increase in asbestos-related personal injury claims brought by former PECO employees, all of which have been reserved for on a claim by claim basis. Those additional claims are taken into account in projecting estimates of future asbestos-related bodily injury claims.

On November 4, 2015, the Illinois Supreme Court found that the provisions of the Illinois' Workers' Compensation Act and the Workers' Occupational Diseases Act barred an employee from bringing a direct civil action against an employer for latent diseases, including asbestos-related diseases that fall outside the 25-year limit of the statute of repose. The Illinois Supreme Court's ruling reversed previous rulings by the Illinois Court of Appeals, which initially ruled that the Illinois Worker's Compensation law should not apply in cases where the diagnosis of an asbestos related disease occurred after the 25-year maximum time period for filing a Worker's Compensation claim. Since the Illinois Supreme Court's ruling in November 2015, Exelon, Generation, and ComEd have not experienced a significant increase in asbestos-related personal injury claims brought by former ComEd employees.

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 adverse effect on Exelon's, Generation's, ComEd's, PECO and BGE's future results of operations and cash flows.

BGE. Since 1993, BGE and certain Constellation (now Generation) subsidiaries have been involved in several actions concerning asbestos. The actions are based upon the theory of "premises liability," alleging that BGE and Generation knew of and exposed individuals to an asbestos hazard. In addition to BGE and Generation, numerous other parties are defendants in these cases.

To date, most asbestos claims which have been resolved relating to BGE and certain Constellation subsidiaries have been dismissed or resolved without any payment and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation's financial results. Presently, there are an immaterial number of asbestos cases pending against BGE and certain Constellation subsidiaries.

Continuous Power Interruption (Exelon and ComEd)

Section 16-125 of the Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law. As of June 30, 2017 and December 31, 2016, ComEd did not have any material liabilities recorded for these storm events.

Baltimore City Franchise Taxes (Exelon and BGE)

The City of Baltimore claims that BGE has maintained electric facilities in the City's public right-of-ways for over one hundred years without the proper franchise rights from the City. BGE has reviewed the City's claim and believes that it lacks merit. BGE has not recorded an accrual for payment of franchise fees for past periods as a range of loss, if any, cannot be reasonably estimated at this time. Franchise fees assessed in future periods may be material to BGE's results of operations and cash flows.

Conduit Lease with City of Baltimore (Exelon and BGE)

On September 23, 2015, the Baltimore City Board of Estimates approved an increase in annual rental fees for access to the Baltimore City underground conduit system effective November 1, 2015, from $12 million to $42 million, subject to an annual increase thereafter based on the Consumer Price Index. BGE subsequently entered into litigation with the City regarding the amount of and basis for establishing the conduit fee. On November 30, 2016, the Baltimore City Board of Estimates approved a settlement agreement entered into between BGE and the City to resolve the disputes and pending litigation related to BGE's use of and payment for the underground conduit system. As a result of the settlement, the parties have entered into a six-year lease that reduces the annual expense to $25 million in the first three years and caps the annual expense in the last three years to not more than $29 million. BGE recorded a credit to Operating and maintenance expense in the fourth quarter of 2016 of approximately $28 million for the reversal of the previously higher fees accrued in the current year as well as the settlement of prior year disputed fee true-up amounts.

Deere Wind Energy Assets (Exelon and Generation)

In 2013, Deere & Company ("Deere") filed a lawsuit against Generation in the Delaware Superior Court relating to Generation's acquisition of the Deere wind energy assets. Under the purchase agreement, Deere was entitled to receive earn-out payments if certain specific wind projects already under development in Michigan met certain development and construction milestones following the sale. In the complaint, Deere seeks to recover a $14 million earn-out payment associated with one such project, which was never completed. Generation has filed counterclaims against Deere for breach of contract, with a right of recoupment and set off. On June 2, 2016, the Delaware Superior Court entered summary judgment in favor of Deere. On January 17, 2017, Generation filed an appeal of the Superior Court's summary judgment decision with the Supreme Court of Delaware. Generation has accrued an amount to cover its potential liability.

City of Everett Tax Increment Financing Agreement (Exelon)

The City of Everett has filed a petition with the Massachusetts Economic Assistance Coordinating Council (EACC) to revoke the 1999 tax increment financing agreement (TIF Agreement) relating to Mystic 8 & 9 on the grounds that the total investment in Mystic 8 & 9 materially deviates from the investment set forth in the TIF Agreement. The EACC has appointed a three-member panel to conduct an administrative hearing on the City's petition. Generation has reviewed the City's claim and believes that it lacks merit. Generation has not recorded an accrual for payment resulting from such a revocation because the range of loss, if any, cannot be reasonably estimated at this time. Property taxes assessed in future periods 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 a reasonable possibility, 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.

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

Income Taxes *(Exelon, Generation, ComEd, PECO and BGE)*

See Note 11 — Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

18. 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 and six months ended June 30, 2017 and 2016.

	Three Months Ended June 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds[(a)]									
Regulatory agreement units	$ 211	$ 211	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-regulatory agreement units	74	74	—	—	—	—	—	—	—
Net unrealized (losses) gains on decommissioning trust funds									
Regulatory agreement units	(13)	(13)	—	—	—	—	—	—	—
Non-regulatory agreement units	70	70	—	—	—	—	—	—	—
Net unrealized losses on pledged assets									
Zion Station decommissioning	(2)	(2)	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities[(b)]	(160)	(160)	—	—	—	—	—	—	—
Total decommissioning-related activities	180	180	—	—	—	—	—	—	—
Investment income	2	1	—	—	—	—	—	—	—
Interest expense related to uncertain income tax positions	(1)	—	—	—	—	—	—	—	—
Penalty related to uncertain income tax positions	1	—	—	—	—	—	—	—	—
AFUDC — Equity	17	—	2	2	4	9	5	2	2
Other	6	—	2	—	—	4	2	1	—
Other, net	$ 205	$ 181	$ 4	$ 2	$ 4	$ 13	$ 7	$ 3	$ 2

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

	Six Months Ended June 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds[(a)]									
Regulatory agreement units	$ 280	$ 280	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-regulatory agreement units	106	106	—	—	—	—	—	—	—
Net unrealized gains on decommissioning trust funds									
Regulatory agreement units	210	210		—	—	—	—	—	—
Non-regulatory agreement units	235	235	—	—	—	—	—	—	—
Net unrealized losses on pledged assets									
Zion Station decommissioning	(2)	(2)		—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities[(b)]	(396)	(396)	—	—	—	—	—	—	—
Total decommissioning-related activities	433	433	—	—	—	—	—	—	—
Investment income (expense)	4	3	—	(1)	—	1	1	—	—
Penalty income related to uncertain income tax positions	2	—	—	—	—	—	—	—	—
AFUDC — Equity	33	—	4	4	8	17	11	3	3
Other	16	4	4	—	—	8	3	3	1
Other, net	$ 488	$ 440	$ 8	$ 3	$ 8	$ 26	$ 15	$ 6	$ 4

	Three Months Ended June 30, 2016								
	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds[(a)]									
Regulatory agreement units	$ 90	$ 90	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-regulatory agreement units	39	39	—	—	—	—	—	—	—
Net unrealized gains on decommissioning trust funds									
Regulatory agreement units	52	52	—	—	—	—	—	—	—
Non-regulatory agreement units	48	48	—	—	—	—	—	—	—
Net unrealized gains on pledged assets									
Zion Station decommissioning	1	1	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities[(b)]	(117)	(117)	—	—	—	—	—	—	—
Total decommissioning-related activities	113	113	—	—	—	—	—	—	—
Investment income	6	5	—	—	—	—	—	—	—
Interest income related to uncertain income tax positions	4	—	—	—	—	—	—	—	—
AFUDC — Equity	15	—	1	2	5	7	5	1	1
Other	6	(1)	2	—	—	4	1	2	1
Other, net	$ 144	$ 117	$ 3	$ 2	$ 5	$ 11	$ 6	$ 3	$ 2

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

	Six Months Ended June 30, 2016								*Successor* March 24, 2016 to June 30, 2016	*Predecessor* January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI	PHI
Other, Net										
Decommissioning-related activities:										
Net realized income on decommissioning trust funds[a]										
Regulatory agreement units	$ 122	$ 122	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-regulatory agreement units	61	61	—	—	—	—	—	—	—	—
Net unrealized gains on decommissioning trust funds										
Regulatory agreement units	131	131	—	—	—	—	—	—	—	—
Non-regulatory agreement units	100	100	—	—	—	—	—	—	—	—
Net unrealized gains on pledged assets										
Zion Station decommissioning	3	3		—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities[b]	(211)	(211)	—	—	—	—	—	—	—	—
Total decommissioning-related activities	206	206	—	—	—	—	—	—	—	—
Investment income (expense)	12	5	—	(1)	2	—	—	—	—	—
Long-term lease income	4	—	—	—	—	—	—	—	—	—
Interest income related to uncertain income tax positions	5	—	—	—	—	1	—	1	—	—
AFUDC — Equity	24	—	3	4	9	9	2	3	8	7
Loss on debt extinguishment	(3)	(2)	—	—	—	—	—	—	—	—
Other	10	1	4	1	—	4	4	1	4	(11)
Other, net	$ 258	$ 210	$ 7	$ 4	$ 11	$ 14	$ 6	$ 5	$ 12	$ (4)

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.
(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 16 — Asset Retirement Obligations of the Exelon 2016 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 and six months ended June 30, 2017 and 2016. 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 on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

	Three Months Ended June 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Utility taxes	$ 213	$ 30	$ 57	$ 29	$ 21	$ 76	$ 72	$ 4	$ —

	Six Months Ended June 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Utility taxes	$ 438	$ 63	$ 116	$ 60	$ 47	$ 152	$143	$ 9	$ —

	Three Months Ended June 30, 2016								
	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Utility taxes	$ 217	$ 27	$ 60	$ 32	$ 21	$ 77	$ 73	$ 4	$ —

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

	Six Months Ended June 30, 2016								*Successor* March 24, 2016 to June 30, 2016	*Predecessor* January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI	PHI
Utility taxes	$ 369	$ 55	$ 119	$ 66	$ 45	$152	$ 9	$ —	$ 84	$ 77

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the six months ended June 30, 2017 and 2016.

	Six Months Ended June 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Depreciation, amortization and accretion									
Property, plant and equipment(a)	$1,545	$ 612	$ 384	$129	$155	$ 227	$101	$61	$ 44
Amortization of regulatory assets(a)	238	—	35	12	84	105	59	18	28
Amortization of intangible assets, net(a)	28	25	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities(b)	20	20	—	—	—	—	—	—	—
Nuclear fuel(c)	529	529	—	—	—	—	—	—	—
ARO accretion(d)	231	229	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$2,591	$ 1,415	$ 419	$141	$239	$ 332	$160	$79	$ 72

	Six Months Ended June 30, 2016								*Successor* March 24, 2016 to June 30, 2016	*Predecessor* January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI	PHI
Depreciation, amortization and accretion										
Property, plant and equipment(a)	$1,432	$ 674	$ 345	$121	$150	$ 85	$55	$ 40	$ 111	$ 94
Amortization of regulatory assets(a)	166	—	34	13	56	59	21	41	63	58
Amortization of intangible assets, net(a)	28	23	—	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities(b)	(7)	(7)	—	—	—	—	—	—	—	—
Nuclear fuel(c)	557	557	—	—	—	—	—	—	—	—
ARO accretion(d)	220	220	—	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$2,396	$ 1,467	$ 379	$134	$206	$144	$76	$ 81	$ 174	$ 152

(a) Included in Depreciation and amortization on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

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

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

	Six Months Ended June 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Other non-cash operating activities:									
Pension and non-pension postretirement benefit costs	$ 320	$ 113	$ 87	$ 14	$ 31	$ 48	$ 13	$ 6	$ 7
Loss from equity method investments	19	19	—	—	—	—	—	—	—
Provision for uncollectible accounts	52	19	15	9	3	6	4	—	2
Stock-based compensation costs	57	—	—	—	—	—	—	—	—
Other decommissioning-related activity[(a)]	(144)	(144)	—	—	—	—	—	—	—
Energy-related options[(b)]	11	11	—	—	—	—	—	—	—
Amortization of regulatory asset related to debt costs	4	—	2	—	—	2	1	1	—
Amortization of rate stabilization deferral	(8)	—	—	—	7	(15)	(10)	(5)	—
Amortization of debt fair value adjustment	(9)	(6)	—	—	—	(3)	—	—	—
Discrete impacts from EIMA and FEJA[(c)]	(51)	—	(51)	—	—	—	—	—	—
Amortization of debt costs	49	30	2	1	1	—	—	—	—
Provision for excess and obsolete inventory	51	49	1	—	—	1	—	—	—
Merger-related commitments[(d)]	—	—	—	—	—	(8)	(6)	(2)	—
Severance costs	25	17	—	—	—	3	—	—	—
Other	39	13	2	(2)	(7)	(6)	(2)	(3)	(2)
Total other non-cash operating activities	$ 415	$ 121	$ 58	$ 22	$ 35	$ 28	$ —	$ (3)	$ 7
Non-cash investing and financing activities:									
Change in capital expenditures not paid	$ (105)	$ 48	$ (82)	$ (44)	$ 6	$ (8)	$ —	$15	$(14)
Fair value of pension obligation transferred in connection with the FitzPatrick acquisition	—	49	—	—	—	—	—	—	—
Change in PPE related to ARO update	103	103	—	—	—	—	—	—	—
Indemnification of like-kind exchange position[(g)]	—	—	23	—	—	—	—	—	—
Non-cash financing of capital projects	13	13	—	—	—	—	—	—	—
Dividends on stock compensation	3	—	—	—	—	—	—	—	—
Loss on reissuance of treasury stock	1,054	—	—	—	—	—	—	—	—

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

	Six Months Ended June 30, 2016								*Successor* March 24, 2016 to June 30, 2016	*Predecessor* January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI	PHI
Other non-cash operating activities:										
Pension and non-pension postretirement benefit costs	$ 297	$ 109	$ 83	$ 17	$ 33	$ 16	$ 9	$ 8	$ 31	$ 23
Loss from equity method investments	10	11	—	—	—	—	—	—	—	—
Provision for uncollectible accounts	51	13	18	10	3	8	8	10	7	16
Stock-based compensation costs	67	—	—	—	—	—	—	—	—	3
Other decommissioning-related activity[(a)]	(123)	(123)	—	—	—	—	—	—	—	—
Energy-related options[(b)]	(17)	(17)	—	—	—	—	—	—	—	—
Amortization of regulatory asset related to debt costs	4	—	2	1	—	1	—	—	1	1
Amortization of rate stabilization deferral	34	—	—	—	34	(2)	2	—	—	5
Amortization of debt fair value adjustment	(6)	(6)	—	—	—	—	—	—	—	—
Discrete impacts from EIMA[(c)]	(21)	—	(21)	—	—	—	—	—	—	—
Amortization of debt costs	14	10	2	1	2	—	—	—	—	—
Provision for excess and obsolete inventory	68	66	2	—	—	1	1	1	—	1
Merger-related commitments[(d)(e)]	503	3	—	—	—	138	100	120	358	—
Severance costs	122	50	—	—	—	—	—	—	54	—
Asset retirement costs	—	—	—	—	—	—	4	2	—	—
Lower of cost or net realizable value inventory adjustment	36	36	—	—	—	—	—	—	—	—
Other	17	17	(3)	(2)	(12)	(4)	(3)	(3)	(7)	(3)
Total other non-cash operating activities	$ 1,056	$ 169	$ 83	$ 27	$ 60	$ 158	$121	$ 138	$ 444	$ 46
Non-cash investing and financing activities:										
Change in capital expenditures not paid	$ (364)	$ (317)	$ (21)	$ (12)	$ 2	$ 11	$ (9)	$ 6	$ (4)	$ 11
Fair value of net assets contributed to Generation in connection with the PHI Merger, net of cash[(d)(f)]	—	119	—	—	—	—	—	—	—	—
Fair value of net assets distributed to Exelon in connection with the PHI Merger, net of cash[(d)(f)]	—	—	—	—	—	—	—	—	127	—
Fair value of pension obligation transferred in connection with the PHI Merger	—	—	—	—	—	—	—	—	53	—
Assumption of member purchase liability	—	—	—	—	—	—	—	—	29	—
Assumption of merger commitment liability	—	—	—	—	—	33	—	—	33	—
Change in PPE related to ARO update	471	471	—	—	—	—	—	—	—	—
Indemnification of like-kind exchange position[(g)]	—	—	5	—	—	—	—	—	—	—
Non-cash financing of capital projects	60	60	—	—	—	—	—	—	—	—
Dividends on stock compensation	2	—	—	—	—	—	—	—	—	—

(a) Includes the elimination of NDT fund 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 16 — Asset Retirement Obligations of the Exelon 2016 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.

(c) Reflects the change in distribution rates pursuant to EIMA and FEJA, which allows for the recovery of distribution costs by a utility through a pre-established performance-based formula rate tariff. Beginning June 1, 2017, also reflects the change in energy efficiency rates pursuant to FEJA, which allows for the recovery of energy efficiency costs by a utility through a pre-established performance-based formula rate tariff. See Note 5 — Regulatory Matters for more information.

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

(d) See Note 4 — Mergers, Acquisitions and Dispositions for additional information related to the merger with PHI.

(e) Excludes $5 million of forgiveness of Accounts receivable related to merger commitments recorded in connection with the PHI Merger, the balance is included within Provision for uncollectible accounts.

(f) Immediately following closing of the PHI Merger, the net assets associated with PHI's unregulated business interests were distributed by PHI to Exelon. Exelon contributed a portion of such net assets to Generation.

(g) See Note 11 — Income Taxes for discussion of the like-kind exchange tax position.

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants as of June 30, 2017 and December 31, 2016.

June 30, 2017	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Property, plant and equipment:									
Accumulated depreciation and amortization	$19,735[(a)]	$ 10,550[(a)]	$4,122	$3,330	$3,358	$ 360	$3,131	$1,212	$1,042
Accounts receivable:									
Allowance for uncollectible accounts	$ 322	$ 102	$ 71	$ 59	$ 26	$ 64	$ 25	$ 19	$ 20

December 31, 2016	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Property, plant and equipment:									
Accumulated depreciation and amortization	$19,169[(b)]	$ 10,562[(b)]	$3,937	$3,253	$3,254	$ 195	$3,050	$1,175	$1,016
Accounts receivable:									
Allowance for uncollectible accounts	$ 334	$ 91	$ 70	$ 61	$ 32	$ 80	$ 29	$ 24	$ 27

(a) Includes accumulated amortization of nuclear fuel in the reactor core of $3,016 million.

(b) Includes accumulated amortization of nuclear fuel in the reactor core of $3,186 million.

PECO Installment Plan Receivables (Exelon and PECO)

PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $11 million and $9 million as of June 30, 2017 and December 31, 2016, respectively. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1 — Significant Accounting Policies of the Exelon 2016 Form 10-K. The allowance for uncollectible accounts balance associated with these receivables at June 30, 2017 of $13 million consists of $1 million, $3 million and $9 million for low risk, medium risk and high risk segments, respectively.

The allowance for uncollectible accounts balance at December 31, 2016 of $13 million consists of $1 million, $3 million and $9 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of June 30, 2017 and December 31, 2016 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1 — Significant Accounting Policies of the Exelon 2016 Form 10-K.

19. Segment Information (All Registrants)

Operating segments for each of the Registrants are determined based on information used by the chief operating decision maker(s) (CODM) in deciding how to evaluate performance and allocate resources at each of the Registrants.

In the first quarter of 2016, following the consummation of the PHI Merger, three new reportable segments were added: Pepco, DPL and ACE. As a result, Exelon has twelve reportable segments, which include ComEd, PECO, BGE, PHI's three reportable segments consisting of Pepco, DPL, and ACE, and Generation's six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other power regions referred to collectively as "Other Power Regions", which includes activities in the South, West and Canada. 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 and return on equity.

Effective with the consummation of the PHI Merger, PHI's reportable segments have changed based on the information used by the CODM to evaluate performance and allocate resources. PHI's reportable segments consist of Pepco, DPL and ACE. PHI's Predecessor periods' segment information has been recast to conform to the current presentation. The reclassification of the segment information did not impact PHI's reported consolidated revenues or net income. PHI's CODM evaluates the performance of and allocates resources to Pepco, DPL and ACE based on net income and return on equity.

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 six 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, which includes portions of Illinois, Pennsylvania, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO, excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Power Regions:
  - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado and parts of New Mexico, Wyoming and South Dakota.
  - 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 revenues net of purchased power and fuel expense (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.

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

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the three and six months ended June 30, 2017 and 2016 is as follows:

Three Months Ended June 30, 2017 and 2016

	Generation[(a)]	ComEd	PECO	BGE	*Successor* PHI[(b)]	Other[(c)]	Intersegment Eliminations	Exelon
Operating revenues[(d)]:								
2017								
Competitive businesses electric revenues	$ 3,719	$ —	$ —	$ —	$ —	$ —	$ (266)	$ 3,453
Competitive businesses natural gas revenues	430	—	—	—	—	—	—	430
Competitive businesses other revenues	25	—	—	—	—	—	—	25
Rate-regulated electric revenues	—	1,357	550	571	1,040	—	(7)	3,511
Rate-regulated natural gas revenues	—	—	80	103	22	—	(1)	204
Shared service and other revenues	—	—	—	—	12	449	(461)	—
2016								
Competitive businesses electric revenues	$ 3,655	$ —	$ —	$ —	$ —	$ —	$ (354)	$ 3,301
Competitive businesses natural gas revenues	367	—	—	—	—	—	—	367
Competitive businesses other revenues	(433)	—	—	—	—	—	(1)	(434)
Rate-regulated electric revenues	—	1,286	587	584	1,030	—	(7)	3,480
Rate-regulated natural gas revenues	—	—	77	96	26	—	(2)	197
Shared service and other revenues	—	—	—	—	10	398	(409)	(1)
Intersegment revenues[(e)]:								
2017	$ 266	$ 3	$ 2	$ 3	$ 12	$ 448	$ (734)	$ —
2016	355	3	2	4	10	398	(771)	1
Net income (loss):								
2017	$ (266)	$ 118	$ 88	$ 45	$ 66	$ 13	$ —	$ 64
2016	28	145	100	34	52	(52)	(1)	306
Total assets:								
June 30, 2017	$ 48,130	$29,160	$11,041	$8,786	$21,190	$10,783	$ (11,986)	$117,104
December 31, 2016	46,974	28,335	10,831	8,704	21,025	10,369	(11,334)	114,904

(a) Generation includes the six reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. Intersegment revenues for Generation for the three months ended June 30, 2017 include revenue from sales to PECO of $34 million, sales to BGE of $99 million, sales to Pepco of $68 million, sales to DPL of $40 million, and sales to ACE of $7 million in the Mid-Atlantic region, and sales to ComEd of $18 million in the Midwest region. For the three months ended June 30, 2016, intersegment revenues for Generation include revenue from sales to PECO of $64 million, sales to BGE of $135 million, sales to Pepco of $88 million, sales to DPL of $43 million, and sales to ACE of $12 million in the Mid-Atlantic region, and sales to ComEd of $13 million in the Midwest region.

(b) Amounts included represent activity for PHI's successor period, three months ended June 30, 2017 and 2016. PHI includes the three reportable segments: Pepco, DPL and ACE.

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

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

(d) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Supplemental Financial Information for total utility taxes for the three months ended June 30, 2017 and 2016.

(e) 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.

Successor PHI:

	Pepco	DPL	ACE	Other[b]	Intersegment Eliminations	PHI
Operating revenues[a]:						
Three months ended June 30, 2017—Successor						
Rate-regulated electric revenues	$ 514	$ 260	$ 270	$ —	$ (4)	$ 1,040
Rate-regulated natural gas revenues	—	22	—	—	—	22
Shared service and other revenues	—	—	—	13	(1)	12
Three months ended June 30, 2016—Successor						
Rate-regulated electric revenues	$ 509	$ 255	$ 270	$ —	$ (4)	$ 1,030
Rate-regulated natural gas revenues	—	26	—	—	—	26
Shared service and other revenues	—	—	—	10	—	10
Intersegment revenues:						
Three months ended June 30, 2017—Successor	$ 1	$ 2	$ 1	$ 13	$ (5)	$ 12
Three months ended June 30, 2016—Successor	1	2	1	10	(4)	10
Net income (loss):						
Three months ended June 30, 2017—Successor	$ 43	$ 19	$ 8	$ (16)	$ 12	$ 66
Three months ended June 30, 2016—Successor	49	12	3	(22)	10	52
Total assets:						
June 30, 2017 — Successor	$7,648	$4,235	$3,478	$10,800	$ (4,971)	$ 21,190
December 31, 2016 — Successor	7,335	4,153	3,457	10,804	(4,724)	21,025

(a) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Supplemental Financial Information for total utility taxes for the three months ended June 30, 2017 and 2016.

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

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

Generation total revenues:

	Three Months Ended June 30, 2017			Three Months Ended June 30, 2016		
	Revenues from external customers(a)	Intersegment revenues	Total Revenues	Revenues from external customers(a)	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 1,356	$ 9	$ 1,365	$ 1,432	$ (16)	$ 1,416
Midwest	1,058	(8)	1,050	1,076	7	1,083
New England	438	(5)	433	352	(1)	351
New York	352	(5)	347	356	(10)	346
ERCOT	247	—	247	207	—	207
Other Power Regions	268	(9)	259	232	(9)	223
Total Revenues for Reportable Segments	3,719	(18)	3,701	3,655	(29)	3,626
Other(b)	455	18	473	(66)	29	(37)
Total Generation Consolidated Operating Revenues	$ 4,174	$ —	$ 4,174	$ 3,589	$ —	$ 3,589

(a) Includes all wholesale and retail electric sales 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 a $15 million and $9 million decrease to revenues for the amortization of intangible assets and liabilities related to commodity contracts recorded at fair value for the three months ended June 30, 2017 and 2016, respectively, unrealized mark-to-market losses of $143 million and $615 million for the three months ended June 30, 2017 and 2016, respectively, and elimination of intersegment revenues.

Generation total revenues net of purchased power and fuel expense:

	Three Months Ended June 30, 2017			Three Months Ended June 30, 2016		
	RNF from external customers(a)	Intersegment RNF	Total RNF	RNF from external customers(a)	Intersegment RNF	Total RNF
Mid-Atlantic	$ 757	$ 26	$ 783	$ 830	$ (2)	$ 828
Midwest	728	—	728	724	4	728
New England	157	(10)	147	118	(8)	110
New York	230	—	230	270	(3)	267
ERCOT	121	(51)	70	111	(34)	77
Other Power Regions	134	(44)	90	123	(27)	96
Total Revenues net of purchased power and fuel for Reportable Segments	2,127	(79)	2,048	2,176	(70)	2,106
Other(b)	(110)	79	(31)	(164)	70	(94)
Total Generation Revenues net of purchased power and fuel expense	$ 2,017	$ —	$2,017	$ 2,012	$ —	$2,012

(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 a $20 million and $12 million decrease to RNF for the amortization of intangible assets and liabilities related to commodity contracts for the three months ended June 30, 2017 and 2016, respectively, unrealized mark-to-market losses of $184 million and $304 million for the three months ended June 30, 2017 and 2016, respectively, and the elimination of intersegment revenue net of purchased power and fuel expense.

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

Six Months Ended June 30, 2017 and 2016

	Generation[(a)]	ComEd	PECO	BGE	Successor PHI[(b)]	Other[(c)]	Intersegment Eliminations	Exelon
Operating revenues[(d)]:								
2017								
Competitive businesses electric revenues	$ 7,437	$ —	$ —	$ —	$ —	$ —	$ (592)	$6,845
Competitive businesses natural gas revenues	1,348	—	—	—	—	—	—	1,348
Competitive businesses other revenues	276	—	—	—	—	—	(1)	275
Rate-regulated electric revenues	—	2,656	1,140	1,237	2,138	1	(16)	7,156
Rate-regulated natural gas revenues	—	—	286	388	87	—	(4)	757
Shared service and other revenues	—	—	—	—	23	870	(893)	—
2016								
Competitive businesses electric revenues	$ 7,352	$ —	$ —	$ —	$ —	$ —	$ (620)	$6,732
Competitive businesses natural gas revenues	1,189	—	—	—	—	—	—	1,189
Competitive businesses other revenues	(212)	—	—	—	—	—	(1)	(213)
Rate-regulated electric revenues	—	2,535	1,232	1,264	1,120	—	(15)	6,136
Rate-regulated natural gas revenues	—	—	273	345	28	—	(5)	641
Shared service and other revenues	—	—	—	—	23	803	(826)	—
Intersegment revenues[(e)]:								
2017	$ 594	$ 9	$ 3	$ 8	$ 23	$ 866	$ (1,503)	$ —
2016	621	8	4	9	23	803	(1,466)	2
Net income (loss):								
2017	$ 144	$ 259	$ 215	$ 169	$ 205	$ 54	$ —	$1,046
2016	285	260	224	135	(257)	(215)	(2)	430

(a) Generation includes the six reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. Intersegment revenues for Generation for the six months ended June 30, 2017 include revenue from sales to PECO of $79 million, sales to BGE of $233 million, sales to Pepco of $152 million, sales to DPL of $91 million, and sales to ACE of $16 million in the Mid-Atlantic region, and sales to ComEd of $23 million in the Midwest region. For the six months ended June 30, 2016, intersegment revenues for Generation include revenue from sales to PECO of $143 million and sales to BGE of $306 million in the Mid-Atlantic region, and sales to ComEd of $18 million in the Midwest region. For the Successor period of March 24, 2016 to June 30, 2016, intersegment revenues for Generation include revenue from sales to Pepco of $94 million, sales to DPL of $47 million, and sales to ACE of $13 million in the Mid-Atlantic region.

(b) Amounts included represent activity for PHI's successor period, six months ended June 30, 2017 and March 24, 2016 through June 30, 2016. PHI includes the three reportable segments: Pepco, DPL and ACE. See tables below for PHI's predecessor period, including Pepco, DPL and ACE, for January 1, 2016 to March 23, 2016.

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

(d) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Supplemental Financial Information for total utility taxes for the six months ended June 30, 2017 and 2016.

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

(e) 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.

Successor and Predecessor PHI:

	Pepco	DPL	ACE	Other[b]	Intersegment Eliminations	PHI
Operating revenues[a]:						
Six Months Ended June 30, 2017—Successor						
Rate-regulated electric revenues	$1,045	$557	$ 544	$ 1	$ (9)	$2,138
Rate-regulated natural gas revenues	—	87	—	—	—	87
Shared service and other revenues	—	—	—	25	(2)	23
March 24, 2016 to June 30, 2016—Successor						
Rate-regulated electric revenues	$ 550	$279	$ 293	$ 3	$ (5)	$1,120
Rate-regulated natural gas revenues	—	29	—	(1)	—	28
Shared service and other revenues	—	—	—	23	—	23
January 1, 2016 to March 23, 2016—Predecessor						
Rate-regulated electric revenues	$ 511	$279	$ 268	$ 42	$ (4)	$1,096
Rate-regulated natural gas revenues	—	56	—	1	—	57
Shared service and other revenues	—	—	—	—	—	—
Intersegment revenues:						
Six Months Ended June 30, 2017 — Successor	$ 3	$ 4	$ 1	$ 24	$ (9)	$ 23
March 24, 2016 to June 30, 2016 — Successor	2	2	1	23	(5)	23
January 1, 2016 to March 23, 2016 — Predecessor	1	2	1	—	(4)	—
Net income (loss):						
Six Months Ended June 30, 2017 — Successor	$ 101	$ 76	$ 36	$ (31)	$ 23	$ 205
March 24, 2016 to June 30, 2016 — Successor	(92)	(86)	(102)	—	23	(257)
January 1, 2016 to March 23, 2016 — Predecessor	32	26	5	(44)	—	19

(a) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Supplemental Financial Information for total utility taxes for the six months ended June 30, 2017 and 2016.

(b) Other primarily includes PHI's corporate operations, shared service entities and other financing and investment activities. For the predecessor period presented, Other includes the activity of PHI's unregulated businesses which were distributed to Exelon and Generation as a result of the PHI Merger.

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

Generation total revenues:

	Six Months Ended June 30, 2017			Six Months Ended June 30, 2016		
	Revenues from external customers(a)	Intersegment revenues	Total Revenues	Revenues from external customers(a)	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 2,785	$ 5	$ 2,790	$ 2,964	$ (28)	$ 2,936
Midwest	2,107	(5)	2,102	2,166	13	2,179
New England	987	(7)	980	823	(2)	821
New York	662	(8)	654	573	(24)	549
ERCOT	439	(1)	438	370	—	370
Other Power Regions	457	(14)	443	456	(9)	447
Total Revenues for Reportable Segments	7,437	(30)	7,407	7,352	(50)	7,302
Other(b)	1,624	30	1,654	977	50	1,027
Total Generation Consolidated Operating Revenues	$ 9,061	$ —	$ 9,061	$ 8,329	$ —	$ 8,329

(a) Includes all wholesale and retail electric sales 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 a $17 million decrease to revenues and an $11 million increase to revenues for the amortization of intangible assets and liabilities related to commodity contracts recorded at fair value for the six months ended June 30, 2017 and 2016, respectively, unrealized mark-to-market losses of $98 million and $553 million for the six months ended June 30, 2017 and 2016, respectively, and elimination of intersegment revenues.

Generation total revenues net of purchased power and fuel expense:

	Six Months Ended June 30, 2017			Six Months Ended June 30, 2016		
	RNF from external customers(a)	Intersegment RNF	Total RNF	RNF from external customers(a)	Intersegment RN	Total RNF
Mid-Atlantic	$ 1,513	$ 44	$1,557	$ 1,661	$ 8	$1,669
Midwest	1,431	12	1,443	1,443	6	1,449
New England	271	(14)	257	204	(13)	191
New York	385	—	385	408	(13)	395
ERCOT	214	(76)	138	192	(54)	138
Other Power Regions	240	(88)	152	211	(37)	174
Total Revenues net of purchased power and fuel expense for Reportable Segments	4,054	(122)	3,932	4,119	(103)	4,016
Other(b)	52	122	174	190	103	293
Total Generation Revenues net of purchased power and fuel expense	$ 4,106	$ —	$4,106	$ 4,309	$ —	$4,309

(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 a $22 million decrease to RNF and a $7 million increase to RNF for the amortization of intangible assets and liabilities related

to commodity contracts for the six months ended June 30, 2017 and 2016, respectively, unrealized mark-to-market losses of $233 million and $201 million for the six months ended June 30, 2017 and 2016, respectively, and the elimination of intersegment revenue net of purchased power and fuel expense.

20. Subsequent Events (Exelon and Generation)

On July 6, 2017, ExGen Renewables Holdings, LLC, a wholly owned subsidiary of Generation, completed the sale of a 49% interest of ExGen Renewables Partners, LLC, a newly formed owner and operator of approximately 1,296 megawatts of Generation's operating wind and solar electric generating facilities. ExGen Renewables Holdings will be the managing member of ExGen Renewables Partners, LLC, and have day-to-day control and management over its renewable generation portfolio. The closing of the transaction was subject to certain regulatory approvals, including the Federal Energy Regulatory Commission (FERC) and the Public Utility Commission of Texas (PUCT) which were received during the second quarter of 2017. The sale price was $400 million plus immaterial working capital and other customary post-closing adjustments. The net proceeds, after approximately $120 million of income taxes, will be used to pay down debt and for general corporate purposes. Generation will continue to consolidate ExGen Renewables Partners, LLC and will record a noncontrolling interest on its Consolidated Balance Sheet for the investor's initial equity share as well as earnings attributable to the noncontrolling interest in the Consolidated Statements of Operations and Comprehensive Income each period going forward.

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, a utility services holding company, operates through the following principal subsidiaries:

- *Generation*, whose integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services.
- *ComEd*, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services in northern Illinois, including the City of Chicago.
- *PECO*, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE*, whose business consists of the purchase and regulated retail sale of electricity and natural gas and the provision of electricity distribution and transmission and natural gas distribution services in central Maryland, including the City of Baltimore.
- *Pepco*, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission in the District of Columbia and major portions of Prince George's County and Montgomery County in Maryland.
- *DPL*, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in northern Delaware.
- *ACE*, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services in southern New Jersey.

Pepco, DPL and ACE are operating companies of PHI, which is a utility services holding company and a wholly owned subsidiary of Exelon.

Exelon has twelve reportable segments consisting of Generation's six reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions in Generation), ComEd, PECO, BGE and PHI's three utility reportable segments (Pepco, DPL and ACE). See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of support services at cost. The costs of these services are directly charged or allocated to the applicable operating segments. Additionally, the results of Exelon's corporate operations include costs for corporate governance and interest costs and income from various investment and financing activities.

PHI Service Company, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, accounting, engineering, distribution and transmission planning, asset management, system operations, and power procurement, to PHI and its operating subsidiaries. These services are directly charged or allocated pursuant to service agreements among PHI Service Company and the participating operating subsidiaries.

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.

Financial Results of Operations

GAAP Results of Operations

The following tables sets forth Exelon's GAAP consolidated results of operations for the three and six months ended June 30, 2017 compared to the same period in 2016. The 2016 amounts include the operations of PHI, Pepco, DPL and ACE from March 24, 2016 through June 30, 2016. All amounts presented below are before the impact of income taxes, except as noted.

	Three Months Ended June 30, 2017							2016	Favorable (Unfavorable) Variance
	Generation	ComEd	PECO	BGE	PHI	Other	Exelon	Exelon[b]	
Operating revenues	$ 4,174	$1,357	$630	$674	$1,074	$(286)	$7,623	$ 6,910	$ 713
Purchased power and fuel	2,157	378	197	234	383	(263)	3,086	2,454	(632)
Revenue net of purchased power and fuel[a]	2,017	979	433	440	691	(23)	4,537	4,456	81
Other operating expenses									
Operating and maintenance	2,010	377	190	174	269	(49)	2,971	2,505	(466)
Depreciation and amortization	334	211	71	112	165	22	915	941	26
Taxes other than income	140	72	35	56	110	7	420	394	(26)
Total other operating expenses	2,484	660	296	342	544	(20)	4,306	3,840	(466)
Gain on sales of assets	—	—	—	—	1	—	1	31	(30)
Operating income (loss)	(467)	319	137	98	148	(3)	232	647	(415)
Other income and (deductions)									
Interest expense, net	(129)	(101)	(31)	(26)	(59)	(90)	(436)	(376)	(60)
Other, net	181	4	2	4	13	1	205	144	61
Total other income and (deductions)	52	(97)	(29)	(22)	(46)	(89)	(231)	(232)	1
Income (loss) before income taxes	(415)	222	108	76	102	(92)	1	415	(414)
Income taxes	(158)	104	20	31	36	(105)	(72)	102	174
Equity in losses of unconsolidated affiliates	(9)	—	—	—	—	—	(9)	(7)	(2)
Net income (loss)	(266)	118	88	45	66	13	64	306	(242)
Net income (loss) attributable to noncontrolling interests and preference stock dividends	(16)	—	—	—		—	(16)	39	55
Net income (loss) attributable to common shareholders	$ (250)	$ 118	$ 88	$ 45	$ 66	$ 13	$ 80	$ 267	$ (187)

(a) The Registrants evaluate operating performance using the measure of revenues net of purchased power and fuel expense. The Registrants believe that revenues net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate their operational performance. Revenues net of purchased power and fuel expense 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.

(b) As a result of the PHI Merger, Exelon includes the consolidated results of PHI, Pepco, DPL and ACE from April 1, 2016 through June 30, 2016.

	Six Months Ended June 30, 2017							2016	Favorable (Unfavorable) Variance
	Generation	ComEd	PECO	BGE	PHI	Other	Exelon	Exelon[b]	
Operating revenues	$ 9,061	$2,656	$1,426	$1,625	$2,248	$(635)	$16,381	$14,485	$ 1,896
Purchased power and fuel expense	4,955	713	484	584	845	(596)	6,985	5,708	(1,277)
Revenue net of purchased power and fuel expense[a]	4,106	1,943	942	1,041	1,403	(39)	9,396	8,777	619
Other operating expenses									
Operating and maintenance	3,497	747	398	357	524	(92)	5,431	5,341	(90)
Depreciation and amortization	637	419	141	239	332	43	1,811	1,626	(185)
Taxes other than income	282	144	74	119	221	17	857	720	(137)
Total other operating expenses	4,416	1,310	613	715	1,077	(32)	8,099	7,687	(412)
Gain on sales of assets	4	—	—	—	1	—	5	40	(35)
Bargain purchase gain	226	—	—	—	—	—	226	—	226
Operating income (loss)	(80)	633	329	326	327	(7)	1,528	1,130	398
Other income and (deductions)									
Interest expense, net	(228)	(185)	(62)	(54)	(122)	(158)	(809)	(663)	(146)
Other, net	440	8	3	8	26	3	488	258	230
Total other income and (deductions)	212	(177)	(59)	(46)	(96)	(155)	(321)	(405)	84
Income (loss) before income taxes	132	456	270	280	231	(162)	1,207	725	482
Income taxes	(31)	197	55	111	26	(215)	143	285	142
Equity in (losses) earnings of unconsolidated affiliates	(19)	—	—	—	—	1	(18)	(10)	(8)
Net income	144	259	215	169	205	54	1,046	430	616
Net loss attributable to noncontrolling interests and preference stock dividends	(30)	—	—	—	—	—	(30)	(10)	20
Net income attributable to common shareholders	$ 174	$ 259	$ 215	$ 169	$ 205	$ 54	$ 1,076	$ 440	$ 636

(a) The Registrants evaluate operating performance using the measure of revenues net of purchased power and fuel expense. The Registrants believe that revenues net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate their operational performance. Revenues net of purchased power and fuel expense 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.

(b) As a result of the PHI Merger, Exelon includes the consolidated results of PHI, Pepco, DPL and ACE from March 24, 2016 through June 30, 2016.

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. Exelon's Net income attributable to common shareholders was $80 million for the three months ended June 30, 2017 as compared to $267 million for the three months ended June 30, 2016, and diluted earnings per average common share were $0.09 for the three months ended June 30, 2017 as compared to $0.29 for the three months ended June 30, 2016.

Revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $81 million for the three months ended June 30, 2017 as compared to the same period in 2016. The quarter-over-quarter increase in Revenue net of purchased power and fuel expense was primarily due to the following favorable factors:

- Increase of $120 million at Generation due to mark-to-market losses of $184 million in 2017 compared to $304 million in 2016;
- Increase of $41 million at PHI primarily due to increased distribution revenue as a result of rate increases effective in 2016 and 2017;
- Increase of $32 million at ComEd primarily due to higher electric distribution and transmission formula rate revenues resulting from increased capital investment, increased Depreciation expense and higher allowed electric distribution ROE due to an increase in treasury rates, partially offset by favorable weather conditions in the second quarter 2016; and
- Increase of $21 million at BGE primarily due to the impacts of the electric and natural gas distribution rate increases effective in June 2016 and July 2016.

The quarter-over-quarter increase in Revenue net of purchase power and fuel expense was partially offset by a decrease of $115 million at Generation due to the conclusion of the Ginna reliability support services agreement, lower realized energy prices and lower optimization in Generation's natural gas portfolio, partially offset by Zero Emission Credit revenue due to the impact of the New York Clean Energy Standard and increased nuclear volumes due to the acquisition of the FitzPatrick nuclear facility.

Operating and maintenance expense increased by $466 million for the three months ended June 30, 2017 as compared to the same period in 2016 primarily due to the following unfavorable factors:

- Increase of $375 million at Generation due to long-lived asset impairments primarily related to the EGTP assets held for sale;
- Increase of $71 million at Generation due to increased nuclear outage costs;
- Increase in Generation's and PHI's labor, contracting and materials expense of $28 million primarily related to the inclusion of FitzPatrick at Generation and increased preventative maintenance expenses at PHI; and
- Increase of $28 million at Generation, BGE and Pepco due to increases in uncollectible accounts.

The quarter-over-quarter increase in Operating and maintenance expense was partially offset by a decrease of $51 million at BGE due to the absence of 2016 charges for certain disallowances contained in the June and July 2016 rate orders.

Depreciation and amortization expense decreased by $26 million primarily due to lower accelerated depreciation and amortization as a result of the 2017 decision to early retire the TMI nuclear facility compared to the previous decision in 2016 to early retire the Clinton and Quad Cities nuclear facilities, partially offset by increased depreciation expense as a result of ongoing capital expenditures across all operating companies for the three months ended June 30, 2017 as compared to the same period in 2016.

Taxes other than income increased by $26 million primarily due to the addition of FitzPatrick and increased gross receipts tax accruals at Generation for the three months ended June 30, 2017 as compared to the same period in 2016.

Gain on sales of assets decreased by $30 million primarily due to Generation's gain associated with sale of the New Boston generating site in 2016.

Interest expense, net increased by $60 million primarily due to higher outstanding debt and additional interest recorded in the second quarter 2017 related to Exelon's like-kind exchange tax position for the three months ended June 30, 2017 as compared to the same period in 2016.

Other, net increased by $61 million primarily due to higher net unrealized and realized gains on NDT funds at Generation for the three months ended June 30, 2017 as compared to the same period in 2016.

Exelon's effective income tax rates for the three months ended June 30, 2017 and 2016 were (7,200.0)% and 24.6%, respectively. The effective tax rate for the three months ended June 30, 2017 is disproportionately impacted due to the decline in pre-tax GAAP earnings and changes in other reconciling items. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. Exelon's Net income attributable to common shareholders was $1,076 million for the six months ended June 30, 2017 as compared to $440 million for the six months ended June 30, 2016, and diluted earnings per average common share were $1.15 for the six months ended June 30, 2017 as compared to $0.48 for the six months ended June 30, 2016.

Revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $619 million for the six months ended June 30, 2017 as compared to the same period in 2016. The year-over-year increase in Revenue net of purchased power and fuel expense was primarily due to the following favorable factors:

- Increase of $94 million at ComEd primarily due to higher electric distribution and transmission formula rate revenues resulting from increased capital investment, increased Depreciation expense and higher allowed electric distribution ROE due to an increase in treasury rates;
- Increase of $66 million at BGE primarily due to the impacts of the electric and natural gas distribution rate increases effective in June 2016 and July 2016; and
- Increase of $686 million in Revenue net of purchased power and fuel due to the inclusion of PHI's results for the six months ended June 30, 2017 compared to the period March 24, 2016 to June 30, 2016, as well as various distribution rate increases effective in 2016 and 2017.

The year-over-year increase in Revenue net of purchased power and fuel expense was partially offset by the following unfavorable factors:

- Decrease of $32 million at Generation due to mark-to-market losses of $233 million in 2017 compared to $201 million in 2016; and
- Decrease of $171 million at Generation primarily due to the impacts of declining natural gas prices and lower optimization in Generation's natural gas portfolio, the conclusion of the Ginna reliability support services agreement, lower realized energy prices and decreased capacity prices, partially offset by Zero Emission Credit revenue due to the impact of the New York Clean Energy Standard and the absence of oil inventory write downs in 2017.

Operating and maintenance expense increased by $90 million for the six months ended June 30, 2017 as compared to the same period in 2016 primarily due to the following unfavorable factors:

- Increase of $266 million at Generation due to long-lived asset impairments primarily related to the EGTP assets held for sale;
- Increase of $99 million at Generation due to increased nuclear outage costs;

- Increase in Generation’s labor, contracting and materials cost of $85 million primarily due to the inclusion of Pepco Energy Services results for the six months ended June 30, 2017 compared to the period March 24, 2016 to June 30, 2016, increased contracting costs related to energy efficiency projects and the inclusion of FitzPatrick from March 31, 2017; and
- Increase of $258 million, exclusive of PHI merger-related costs discussed below, in Operating and maintenance expense due to the inclusion of PHI’s results for the six months ended June 30, 2017 compared to the period March 24, 2016 to June 30, 2016.

The year-over-year increase in Operating and maintenance expense was partially offset by the following favorable factors:

- Decrease of $126 million at Exelon, exclusive of PHI merger–related costs discussed below, due to merger commitment and other merger-related costs of $74 million in 2017 compared to $200 million in 2016;
- Decrease of $51 million at BGE due to the absence of 2016 charges for certain disallowances contained in the June and July 2016 rate orders; and
- Decrease of $429 million at PHI primarily due to merger commitment and other merger-related costs of $419 million recognized in the period March 24, 2016 to June 30, 2016.

Depreciation and amortization expense increased by $185 million primarily due to increased depreciation expense as a result of ongoing capital expenditures across all operating companies and the inclusion of PHI’s results for the six months ended June 30, 2017 compared to the period March 24, 2016 to June 30, 2016, partially offset by lower accelerated depreciation and amortization as a result of the 2017 decision to early retire the TMI nuclear facility compared to the previous decision in 2016 to early retire the Clinton and Quad Cities nuclear facilities.

Taxes other than income increased by $137 million primarily due to the addition of FitzPatrick and increased gross receipts tax accruals at Generation and the inclusion of PHI’s results for the six months ended June 30, 2017 compared to the period March 24, 2016 to June 30, 2016.

Gain on sales of assets decreased by $35 million primarily due to Generation’s gain associated with the sale of the New Boston generating site in 2016.

Bargain purchase gain increased by $226 million due to the gain associated with Generation’s FitzPatrick acquisition for the six months ended June 30, 2017 as compared to the same period in 2016.

Interest expense, net increased by $146 million primarily due to higher outstanding debt, additional interest recorded in the second quarter 2017 related to Exelon’s like-kind exchange tax position and the inclusion of PHI’s results for the six months ended June 30, 2017 compared to the period March 24, 2016 to June 30, 2016.

Other, net increased by $230 million primarily due to higher net unrealized and realized gains on NDT funds at Generation for the six months ended June 30, 2017 as compared to the same period in 2016.

Exelon’s effective income tax rates for the six months ended June 30, 2017 and 2016 were 11.8% and 39.3%, respectively. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

For further detail regarding the financial results for the three and six months ended June 30, 2017, including explanation of the non-GAAP measure Revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

Adjusted (non-GAAP) Operating Earnings

Exelon's adjusted (non-GAAP) operating earnings for the three months ended June 30, 2017 were $509 million, or $0.54 per diluted share, compared with adjusted (non-GAAP) operating earnings of $604 million, or $0.65 per diluted share for the same period in 2016. Exelon's adjusted (non-GAAP) operating earnings for the six months ended June 30, 2017 were $1,114 million, or $1.19 per diluted share, compared with adjusted (non-GAAP) operating earnings of $1,235 million, or $1.33 per diluted share for the same period in 2016. 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 period-over-period operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the three and six months ended June 30, 2017 as compared to the same period in 2016. The footnotes below the table provide tax expense (benefit) impacts:

	Three Months Ended June 30,			
	2017		2016	
(All amounts in millions after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$ 80	$ 0.09	$267	$ 0.29
Mark-to-Market Impact of Economic Hedging Activities[(a)] (net of taxes of $72 and $120, respectively)	113	0.12	185	0.20
Unrealized Gains Related to NDT Fund Investments[(b)] (net of taxes of $20 and $29, respectively)	(45)	(0.05)	(27)	(0.03)
Amortization of Commodity Contract Intangibles[(c)] (net of taxes of $8 and $4, respectively)	12	0.01	8	0.01
Merger and Integration Costs[(d)] (net of taxes of $9 and $0, respectively)	15	0.01	1	—
Merger Commitments[(e)] (entire amount represents tax expense)	—	—	1	—
Long-Lived Asset Impairments[(f)] (net of taxes of $172 and $14, respectively)	268	0.29	22	0.02
Plant Retirements and Divestitures[(g)] (net of taxes of $42 and $85, respectively)	66	0.07	133	0.14
Cost Management Program[(i)] (net of taxes of $4 and $3, respectively)	6	0.01	6	0.01
Like-Kind Exchange Tax Position[(l)] (net of taxes of $66)	(26)	(0.03)	—	—
CENG Noncontrolling Interest[(m)] (net of taxes of $5 and $1, respectively)	20	0.02	8	0.01
Adjusted (non-GAAP) Operating Earnings	$509	$ 0.54	$604	$ 0.65

(All amounts in millions after tax)	Six Months Ended June 30, 2017		2016	
		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$1,076	$ 1.15	$ 440	$ 0.48
Mark-to-Market Impact of Economic Hedging Activities[(a)] (net of taxes of $91 and $81, respectively)	142	0.15	121	0.12
Unrealized Gains Related to NDT Fund Investments[(b)] (net of taxes of $130 and $64, respectively)	(144)	(0.15)	(59)	(0.07)
Amortization of Commodity Contract Intangibles[(c)] (net of taxes of $9 and $2, respectively)	15	0.02	(4)	—
Merger and Integration Costs[(d)] (net of taxes of $25 and $26, respectively)	40	0.04	79	0.09
Merger Commitments[(e)] (net of taxes of $137 and $113, respectively)	(137)	(0.15)	395	0.43
Long-Lived Asset Impairments[(f)] (net of taxes of $172 and $62, respectively)	268	0.29	93	0.10
Plant Retirements and Divestitures[(g)] (net of taxes of $42 and $85, respectively)	66	0.07	133	0.14
Reassessment of State Deferred Income Taxes[(h)] (entire amount represents tax expense)	(20)	(0.02)	—	—
Cost Management Program[(i)] (net of taxes of $7 and $12, respectively)	10	0.01	19	0.02
Tax Settlements[(j)] (net of taxes of $1)	(5)	(0.01)	—	—
Bargain Purchase Gain[(k)]	(226)	(0.24)	—	—
Like-Kind Exchange Tax Position[(l)] (net of taxes of $66)	(26)	(0.03)	—	—
CENG Noncontrolling Interest[(m)] (net of taxes of $12 and $3, respectively)	55	0.06	18	0.02
Adjusted (non-GAAP) Operating Earnings	$1,114	$ 1.19	$1,235	$ 1.33

Note:

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 ranged from 39 percent to 41 percent. Under IRS regulations, NDT fund investment returns are taxed at differing rates for investments in qualified vs. non-qualified funds. The tax rates applied to unrealized gains and losses related to NDT Fund investments were 31.4 percent and 47.5 percent for the three and six months ended June 30, 2017, respectively, and 51.6 percent and 52.5 percent for the three and six months ended June 30, 2016, respectively.

(a) Reflects the impact of net losses on Generation's economic hedging activities. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(b) Reflects the impact of net unrealized gains on Generation's NDT fund investments for Non-Regulatory Agreement Units. See Note 12 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Reflects the non-cash impact of the amortization of intangible assets, net, primarily related to commodity contracts recorded at fair value for the Integrys acquisition in 2016, and in 2017, the ConEdison Solutions and FitzPatrick acquisitions.

(d) Reflects certain costs incurred for the PHI acquisition in 2017 and 2016 and Generation's FitzPatrick acquisition in 2017, including professional fees, employee-related expenses and integration activities. See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional detail related to merger and acquisition costs.

(e) Represents a decrease in reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2012 CEG and 2016 PHI acquisitions in 2017, and costs and adjustments incurred as part of the settlement orders approving the PHI acquisition in 2017 and 2016. See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional detail related to PHI Merger commitments.
(f) Primarily reflects impairments as a result of the ExGenTexas Power, LLC assets held for sale in 2017 and impairments of Upstream assets and certain wind projects at Generation in 2016.
(g) Primarily reflects accelerated depreciation and amortization expenses, increases to materials and supplies inventory reserves, charges for severance reserves and construction work in progress impairments associated with Generation's previous decision to early retire the Clinton and Quad Cities nuclear facilities in 2016, partially offset in 2016 by a gain associated with Generation's sale of the New Boston generating site and Generation's decision to early retire the Three Mile Island nuclear facility in 2017.
(h) Reflects the non-cash impact of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment related to the PHI acquisition in 2016, and in 2017, and a change in the statutory tax rate.
(i) Reflects reorganization costs, and in 2016 severance costs, related to a cost management program for 2016 and 2017.
(j) Reflects benefits related to the favorable settlement of certain income tax positions related to PHI's unregulated business interests in 2017.
(k) Represents the excess of the fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition.
(l) Represents adjustments to income tax, penalties and interest expenses as a result of the finalization of the IRS tax computation related to Exelon's like-kind exchange tax position in 2017.
(m) Represents Generation's noncontrolling interest related to CENG exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments and mark-to-market activity.

Merger and Acquisition Costs

On March 23, 2016, the Exelon and PHI Merger was completed. On the merger date, PHI shareholders received $27.25 of cash in exchange for each share of PHI common stock. The resulting company retained the Exelon name and is headquartered in Chicago.

As a result of the PHI Merger, Exelon has incurred costs associated with evaluating, structuring and executing the PHI Merger transaction itself, and will continue to incur cost associated with meeting the various commitments set forth by regulators and agreed-upon with other interested parties as part of the merger approval process, and integrating the former PHI businesses into Exelon.

For the three and six months ended June 30, 2017 and 2016, expense has been recognized for the PHI Merger and Generation's FitzPatrick acquisition as follows:

	Pre-tax Expense Three Months Ended June 30, 2017								
Merger, Integration and Acquisition Costs:	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Transaction[a]	$ 4	$ 3	$ —	$ —	$—	$—	$ —	$—	$ —
Other[b]	20	15	1	1	1	3	1	—	1
Total	$ 24	$ 18	$ 1	$ 1	$ 1	$ 3	$ 1	$—	$ 1

	Pre-tax Expense Three Months Ended June 30, 2016								
Merger, Integration and Acquisition Costs:	**Exelon[d]**	**Generation[d]**	**ComEd**	**PECO**	**BGE[e]**	**PHI[d][f]**	**Pepco[d][g]**	**DPL[d][h]**	**ACE[d]**
Employee-Related[c]	$ 2	$ (1)	$ (1)	$ —	$ —	$ 4	$ 2	$ 1	$ 1
Other[b]	(1)	5	2	1	(5)	(5)	(6)	(1)	1
Total	$ 1	$ 4	$ 1	$ 1	$ (5)	$ (1)	$ (4)	$ —	$ 2

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Merger, Integration and Acquisition Costs:	Exelon	Generation	ComEd	PECO	BGE	PHI[f]	Pepco	DPL[h]	ACE
	Pre-tax Expense Six Months Ended June 30, 2017								
Transaction[a]	$ 5	$ 4	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Other[b]	60	56	1	2	2	(2)	2	(7)	2
Total	$ 65	$ 60	$ 1	$ 2	$ 2	$ (2)	$ 2	$ (7)	$ 2

Merger and Integration Costs:	Exelon[d]	Generation[d]	ComEd[i]	PECO	BGE[e]	PHI[d][f]	Pepco[d][g]	DPL[d][h]	ACE[d]
	Pre-tax Expense Six Months Ended June 30, 2016								
Transaction[a]	$ 35	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Employee-Related[c]	73	10	1	1	1	60	29	17	14
Other[b]	(5)	10	(8)	1	(5)	(5)	(6)	(1)	1
Total	$ 103	$ 20	$ (7)	$ 2	$ (4)	$ 55	$ 23	$ 16	$ 15

(a) External, third party costs paid to advisors, consultants, lawyers and other experts to integrate PHI processes and systems into Exelon, to assist in the due diligence and regulatory approval processes and in the closing of transactions.

(b) Costs to integrate PHI processes and systems into Exelon. For the three and six months ended June 30, 2017, also includes costs to integrate FitzPatrick processes and systems into Exelon.

(c) Costs primarily for employee severance, pension and OPEB expense and retention bonuses.

(d) For Exelon, Generation, PHI, Pepco, DPL, and ACE, includes the operations of the acquired businesses beginning on March 24, 2016.

(e) For the three and six months ended June 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $6 million incurred at BGE that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for more information.

(f) For the six months ended June 30, 2017, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million incurred at PHI that have been deferred and recorded as a regulatory asset for anticipated recovery. For the three months ended June 30, 2016 and the Successor period March 24, 2016 to June 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $12 million incurred at PHI that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 — Regulatory Matters for more information.

(g) For the three and six months ended June 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $9 million incurred at Pepco that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 — Regulatory Matters for more information.

(h) For the six months ended June 30, 2017, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million incurred at DPL that have been deferred and recorded as a regulatory asset for anticipated recovery. For the three and six months ended June 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $3 million incurred at DPL that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 — Regulatory Matters for more information.

(i) For the six months ended June 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million incurred at ComEd that has been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for more information.

As of June 30, 2017, Exelon expects to incur total PHI acquisition and integration related costs of approximately $700 million, excluding merger commitments. Of this amount, including costs incurred from 2014 through June 30, 2017, Exelon and PHI have incurred approximately $660 million.

Significant 2017 Transactions and Developments

Early Retirement of Three Mile Island Facility

On May 30, 2017, Generation announced it will permanently cease generation operations at Three Mile Island Generating Station (TMI) on or about September 30, 2019. The TMI nuclear plant did not clear in the May 2017 PJM capacity auction for the 2020-2021 planning year and will not receive capacity revenue for that period, the third consecutive year that TMI failed to clear the PJM base residual capacity auction. The plant is currently committed to operate through May 2019. In the second quarter of 2017, as a result of the plant retirement decision of TMI, Exelon and Generation recognized one-time charges in Operating and maintenance expense of $71 million related to materials and supplies inventory reserve adjustments, employee-related costs and construction work-in-progress (CWIP) impairments, among other items. In addition to these one-time charges, there will be ongoing annual incremental non-cash charges to earnings stemming from shortening the expected economic useful life of TMI primarily related to accelerated depreciation of plant assets (including any asset retirement costs (ARC)), accelerated amortization of nuclear fuel, and additional asset retirement obligation (ARO) accretion expense associated with the changes in decommissioning timing and cost assumptions. Exelon's and Generation's second quarter 2017 results include an incremental $37 million of pre-tax expense for these items.

The following table summarizes the estimated annual amount and timing of expected incremental non-cash expense items through 2019.

	Projected[a]		
Income statement expense (pre-tax)	2017	2018	2019
Depreciation and Amortization			
Accelerated depreciation[b]	$250	$430	$325
Accelerated nuclear fuel amortization	10	20	5
Total	$260	$450	$330

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

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

EGTP Consent Agreement

In September 2014, EGTP, an indirect subsidiary of Exelon and Generation, issued $675 million aggregate principal amount of a nonrecourse senior secured term loan. EGTP's operating cash flows have been negatively impacted by certain market conditions and the seasonality of its cash flows. On May 2, 2017, EGTP entered into a consent agreement with its lenders to permit EGTP to draw on its revolving credit facility and initiate an orderly sales process to sell the assets of its wholly owned subsidiaries, the proceeds from which will first be used to pay the administrative costs of the sale, the normal and ordinary costs of operating the plants and repayment of the secured debt of EGTP, including the revolving credit facility. As a result, in the second quarter 2017, Exelon and Generation classified certain EGTP assets and liabilities on Exelon's and Generation's Consolidated Balance Sheets as held for sale at their respective fair values less costs to sell and included in the other current assets and other current liabilities balances on Exelon's and Generation's Consolidated Balance Sheets. At June 30, 2017, a $418 million pre-tax impairment loss was recorded within Operating and maintenance expense on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. See Note 4 — Mergers, Acquisitions and Dispositions, Note 6—Impairment of Long-Lived Assets and Note 10 — Debt and Credit Agreements for additional information regarding EGTP and the associated nonrecourse debt.

Acquisition of James A. FitzPatrick Nuclear Generating Station

On March 31, 2017, Generation acquired the 838 MW single-unit James A. FitzPatrick (FitzPatrick) nuclear generating station for a total purchase price of $293 million. In accounting for the acquisition as a business combination, Exelon and Generation recorded an after-tax bargain purchase gain of $226 million which is included within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information regarding the Generation's acquisition of Fitzpatrick and related costs.

Illinois Future Energy Jobs Act

On December 7, 2016, FEJA was signed into law by the Governor of Illinois. FEJA was effective June 1, 2017, and includes, among other provisions, (1) a Zero Emission Standard (ZES) providing compensation for certain nuclear-powered generating facilities, (2) an extension of and certain adjustments to ComEd's electric distribution formula rate, (3) new cumulative persisting annual energy efficiency MWh savings goals for ComEd, (4) revisions to the Illinois RPS requirements, (5) provisions for adjustments to or termination of FEJA programs if the average impact on ComEd's customer rates exceeds specified limits, (6) revisions to the existing net metering statute and (7) support for low income rooftop and community solar programs. FEJA establishes new or adjusts existing rate recovery mechanisms for ComEd to recover costs associated with the new or expanded energy efficiency and RPS requirements. Regulatory or legal challenges over the validity of FEJA are possible. See Note 5 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information regarding FEJA. See Note 7 — Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information regarding the economic challenges facing Generation's Clinton & Quad Cities nuclear plants and the expected benefits of the ZES.

Dismissal of Litigation Challenging ZEC Programs

On July 14, 2017, the U.S. District Court for the Northern District of Illinois dismissed two lawsuits challenging the ZEC program contained in FEJA. On July 17, 2017, the plaintiffs appealed the court's decisions to the U.S. Court of Appeals for the Seventh Circuit. Additionally, on July 25, 2017, the U.S. District Court for the Southern District of New York dismissed a lawsuit challenging the ZEC program contained in the New York CES. The plaintiffs in the New York case have indicated that they intend to appeal. These court decisions uphold the ZEC programs which support Illinois's and New York's efforts to advance clean energy and preserve affordable and reliable energy resources for customers. See Note 5 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information regarding FEJA and the New York CES.

Merger Commitment Unrecognized Tax Benefits

Exelon established a liability for an uncertain tax position associated with the tax deductibility of certain merger commitments incurred by Exelon in connection with the acquisitions of Constellation in 2012 and PHI in 2016. In the first quarter 2017, as a part of its examination of Exelon's return, the IRS National Office issued guidance concurring with Exelon's position that the merger commitments were deductible. As a result, Exelon, Generation, PHI, Pepco, DPL, and ACE decreased their liability for unrecognized tax benefits by $146 million, $19 million, $59 million, $21 million, $16 million, and $22 million, respectively, as of June 30, 2017, resulting in a benefit to Income taxes on Exelon's, Generation's, PHI's, Pepco's, DPL's and ACE's Consolidated Statements of Operations and Comprehensive Income and corresponding decreases in their effective tax rates.

Combined-Cycle Gas Turbine Projects

In June 2017, Generation commenced commercial operations of two new combined-cycle gas turbines (CCGTs) at the Colorado Bend and Wolf Hollow Generating Stations in Texas. The two new CCGTs have added nearly 2,200 MWs of capacity to Generation's fleet, enhancing Generation's strategy to match generation to customer load. Generation invested approximately $1.5 billion over the past three years to complete the new plant construction, which utilizes new General Electric technology to make them among the cleanest, most efficient CCGTs in the nation.

ComEd Distribution Formula Rate

On April 13, 2017, ComEd filed its annual distribution formula rate with the ICC pursuant to EIMA. The filing establishes the revenue requirement used to set the rates that will take effect in January 2018 after the ICC's review and approval, which is due by December 2017. The revenue requirement requested is based on 2016 actual costs plus projected 2017 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2016 to the actual costs incurred that year. ComEd's 2017 filing request includes a total increase to the revenue requirement of $96 million, reflecting an increase of $78 million for the initial revenue requirement for 2017 and a increase of $18 million related to the annual reconciliation for 2016. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information related to distribution formula rate updates.

Pepco Maryland Electric Distribution Rates

On March 24, 2017, Pepco filed an application with the MDPSC requesting an increase of $69 million based on a ROE of 10.1%. The application includes a request for an income tax adjustment to reflect full normalization of removal costs associated with pre-1981 property, which accounts for $18 million of the requested increase. Pepco expects a decision in the matter in the fourth quarter of 2017, but cannot predict how much of the requested rate increase the MDPSC will approve or if it will approve the requested income tax adjustment.

DPL Maryland Electric Distribution Rates

On July 14, 2017, DPL filed an application with the MDPSC to increase its annual electric distribution base rates by $27 million based on a requested ROE of 10.1%. DPL expects a decision on the matter in the first quarter of 2018. DPL cannot predict how much of the requested increase the MDPSC will approve.

On February 15, 2017, the MDPSC approved an increase in DPL electric distribution rates of $38 million based on a ROE of 9.6%. The new rates became effective for services rendered on or after February 15, 2017. The MDPSC also denied DPL's request to continue its Grid Resiliency Program, through which DPL proposed to invest $4.6 million a year for two years to improve priority feeders and install single-phase reclosing fuse technology.

DPL Delaware Electric and Natural Gas Distribution Rates

On May 17, 2016, DPL filed an application with the DPSC to increase its annual electric and natural gas distribution base rates by $63 million (which was updated to $60 million on March 8, 2017) and $22 million, respectively, based on a requested ROE of 10.6%. Delaware law allowed DPL to put into effect $2.5 million of each of the rate increases effective July 16, 2016. On December 17, 2016, the DPSC approved an additional $29.6 million in electric distribution rates and an additional $10.4 million in natural gas distribution rates effective December 17, 2016, subject to refund based on the final DPSC orders.

On March 8, 2017, DPL entered into a settlement agreement with the Division of the Public Advocate, Delaware Electric Users Group and the DPSC Staff in its electric distribution rate proceeding, which provides for an increase in DPL annual electric distribution base rates of $31.5 million based on an ROE of 9.7% compared to the $32.1 million increase previously put into effect. On May 23, 2017, the DPSC issued an order approving the settlement agreement, with the new rates effective June 1, 2017. Pursuant to the settlement agreement, no refund of the interim rates put into effect on July 16, 2016 and December 17, 2016 (as discussed above) is required.

On April 6, 2017, DPL entered into a settlement agreement with the Division of the Public Advocate and the DPSC Staff in its natural gas distribution rate proceeding, which provides for an increase in DPL annual natural gas distribution base rates of $4.9 million based on an ROE of 9.7%. The settlement agreement also provides that DPL will refund amounts collected under the temporary rates effective July 16, 2016 and December 17, 2016 (as discussed above) in excess of the $4.9 million, and that the new rates will be effective within thirty days of DPSC approval of the settlement agreement. On June 6, 2017, the DPSC issued an order approving the settlement agreement, with the new rates effective July 1, 2017. Pursuant to the settlement agreement, a rate refund plus interest of approximately $5 million will be issued to customers beginning in August 2017 for which a regulatory liability has been recorded as of June 30, 2017.

Pepco DC Electric Distribution Rates

On June 30, 2016, Pepco filed an application with the DCPSC to increase its annual electric distribution base rates by $86 million, as updated to approximately $77 million on February 1, 2017, based on a requested ROE of 10.6%.

On July 25, 2017, the DCPSC issued an order granting Pepco an increase to its annual electric distribution base rates of $36.9 million based on an ROE of 9.5%. The new rates will be effective August 15, 2017. In its decision, the DCPSC ordered that the $25.6 million customer rate credit created as a result of the Exelon and PHI merger will be provided primarily to residential customers and some small commercial customers to offset the impact of this increase until that amount has been exhausted, which is expected to take approximately two years. Additionally, the Commission is holding approximately $6 million to $7 million of the customer rate credit for use toward a possible new class of customers for certain senior citizens and disabled persons. The DCPSC also held that Pepco's bill stabilization adjustment, which decouples distribution revenues from utility customers from the amount of electricity delivered, will continue to be in place and that no refund of previously collected funds is required. Parties have 30 days from the date of the order to file for reconsideration with the DCPSC.

2017 ACE New Jersey Electric Distribution Rates

On March 30, 2017, ACE submitted an application with the NJBPU to increase its electric distribution rates by approximately $70 million (before New Jersey sales and use tax), which was updated to $72.6 million on July 14, 2017, based upon a requested ROE of 10.1%. The application also requests approval of a rate surcharge mechanism called the "System Renewal Recovery Charge," which would permit more timely recovery of certain costs associated with reliability and system renewal-related capital investments. ACE currently expects a decision in this matter in the first quarter of 2018, but cannot predict how much of the requested increase the NJBPU will approve.

2016 ACE New Jersey Electric Distribution Rates

On August 24, 2016, the NJBPU issued an order approving a stipulation of settlement among ACE, the New Jersey Division of Rate Counsel, NJBPU Staff and Unimin Corporation, which, among other things, provided that a determination on ACE's grid resiliency program, PowerAhead, would be separated into a phase II of the rate proceeding and decided at a later date. PowerAhead includes capital investments to enhance the resiliency of the system through improvements focused on improving the distribution system's ability to withstand major storm events. A stipulation of settlement with respect to the PowerAhead program (the PowerAhead Stipulation) was approved by the NJBPU on May 31, 2017. As adopted, the PowerAhead program includes an approved investment level of $79 million to be recovered through the cost recovery mechanism described in the PowerAhead Stipulation. The NJBPU order adopting the PowerAhead Stipulation was effective on June 10, 2017.

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Transmission Formula Rate

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

	2017				
Annual Transmission Filings[(a)]	**ComEd**	**BGE**	**Pepco**	**DPL**	**ACE**
Initial revenue requirement increase	$ 44	$ 31	$ 5	$ 6	$ 20
Annual reconciliation (decrease) increase	(33)	3	15	8	22
Dedicated facilities decrease[(b)]	—	(8)	—	—	—
Total revenue requirement increase	$ 11	$ 26	$ 20	$ 14	$ 42
Allowed return on rate base[(c)]	8.43%	7.47%	7.92%	7.16%	8.02%
Allowed ROE[(d)]	11.50%	10.50%	10.50%	10.50%	10.50%

(a) All rates are effective June 2017, subject to review by the FERC and other parties, which is due by fourth quarter 2017.
(b) BGE's transmission revenues include a FERC approved dedicated facilities charge to recover the costs of providing transmission service to specifically designated load by BGE.
(c) Represents the weighted average debt and equity return on transmission rate bases.
(d) As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.50% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%. As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL and ACE, the rate of return on common equity is 10.50%, inclusive of a 50 basis point incentive adder for being a member of a regional transmission organization.

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 would 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. PECO cannot predict the final outcome of the settlement or hearing proceedings, or the transmission formula FERC may approve.

Westinghouse Electric Company LLC Bankruptcy

On March 29, 2017, Westinghouse Electric Company LLC (Westinghouse) and its affiliated debtors filed petitions for relief under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York. In the petitions and supporting documents, Westinghouse makes clear that its requests for relief center on one business area that is losing money — the construction of nuclear power plants in Georgia and South Carolina. Through the bankruptcy, Westinghouse seeks to reorganize around its profitable core business, which includes nuclear fuel fabrication and related services and other services provided to existing nuclear power plants in the U.S. and around the world. For these reasons, at this time, Generation does not anticipate disruption to the Westinghouse fuel fabrication contracts for Braidwood, Byron, or Ginna or other existing contracts for Generation's nuclear power plants. Generation is monitoring the bankruptcy proceeding to ensure that its rights are protected.

ExGen Renewables Holdings, LLC Transaction

On July 6, 2017, ExGen Renewables Holdings, LLC, a wholly owned subsidiary of Generation, completed the sale of a 49% interest of ExGen Renewables Partners, LLC, a newly formed owner and operator of approximately 1,296 megawatts of Generation's operating wind and solar electric generating facilities. ExGen Renewables Holdings will be the managing member of ExGen Renewables Partners, LLC, and have day-to-day control and management over its renewable generation portfolio. The closing of the transaction was subject to certain regulatory approvals, including the Federal Energy Regulatory Commission (FERC) and the Public Utility Commission of Texas (PUCT) which were received during the second quarter of 2017. The sale price was $400 million plus immaterial working capital and other customary post-closing adjustments. The net proceeds, after approximately $120 million of income taxes, will be used to pay down debt and for general corporate purposes. Generation will continue to consolidate ExGen Renewables Partners, LLC and will record a noncontrolling interest on its Consolidated Balance Sheet for the investor's initial equity share as well as earnings attributable to the noncontrolling interest in the Consolidated Statements of Operations and Comprehensive Income each period going forward.

Exelon's Strategy and Outlook for 2017 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:

- Exelon's utilities 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 Exelon utilities 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 Exelon utilities 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 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 2.5% each year for three years, beginning with the June 2016 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 2016 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 a cost management program initiated late in 2015, the company committed to reducing operation and maintenance expenses and capital costs by approximately $350 million and $50 million, respectively, of which approximately 35% of run-rate savings was achieved by the end of 2016. Approximately 60% of run-rate savings are expected to be achieved by the end of 2017 and fully realized in 2018. At least 75% of the savings are expected to be related to Generation, with the remaining amount related to the Utility Registrants.

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 PHI merger provides an opportunity to accelerate Exelon's regulated growth to provide stable cash flows, earnings accretion, and dividend support. Additionally, the Utility Registrants anticipate investing approximately $25 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 $9 billion by the end of 2021. 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 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements 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 prioritize investments in long-term contracted generation across multiple technologies and identify and capitalize on opportunities that provide generation to load matching as a means to provide stable earnings, while identifying emerging technologies where strategic investments provide the option for significant future growth or influence in market development. As of June 30, 2017, Generation has currently approved plans to invest a total of approximately $600 million over the next two years to complete new plant construction currently in progress.

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, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.6 billion, $5.3 billion, $1 billion, $0.6 billion, $0.6 billion, $0.3 billion, $0.3 billion and $0.3 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.5 billion. See Liquidity and Capital Resources—Credit Matters—Exelon Credit Facilities below.

For further detail regarding the Registrants' liquidity for the six months ended June 30, 2017, see Liquidity and Capital Resources discussion below.

Project Financing

Generation utilizes individual project financings as a means to finance the construction of various generating asset projects. Project financing is based upon a nonrecourse financial structure, in which project debt and equity used to finance the project are paid back from the cash generated by the newly constructed asset once operational. 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. See Note 10 — Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on nonrecourse debt.

Other Key Business Drivers and Management Strategies

Utility Rates and Rate Proceedings

The Utility Registrants file rate cases with their regulatory commissions seeking increases or decreases to their electric transmission and distribution, and gas distribution rates to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the Utility Registrants' current and future results of operations, cash flows and financial position. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further details on these regulatory proceedings.

Power Markets

Price of Fuels

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

Capacity Market Changes in PJM

In the wake of the January 2014 Polar Vortex that blanketed much of the Eastern and Midwestern United States, it became clear that while a major outage event was narrowly avoided, resources in PJM were not providing the level of reliability expected by customers. As a result, on December 12, 2014, PJM filed at FERC a proposal to make significant changes to its current capacity market construct, the Reliability Pricing Model (RPM). PJM's proposed changes generally sought to improve resource performance and reliability largely by limiting the excuses for non-performance and by increasing the penalties for performance failures. The proposal permits suppliers to include in capacity market offers additional costs and risk so they can meet these higher performance requirements. While offers are expected to put upward pressure on capacity clearing prices, operational improvements made as a result of PJM's proposal are expected to improve reliability, to reduce energy production costs as a result of more efficient operations and to reduce the need for out of market energy payments to suppliers. Generation participated actively in PJM's stakeholder process through which PJM developed the proposal and also actively participated in the FERC proceeding including filing comments. On June 9, 2015, FERC approved PJM's filing largely as proposed by PJM, including transitional auction rules for delivery years 2016/2017 through 2017/2018. As a result of this and several related orders, PJM hosted its 2018/2019 Base Residual Auction (results posted on August 21, 2015) and its transitional auction for delivery year 2016/2017 (results posted on August 31, 2015) and its transitional auction for delivery years 2017/2018 (results posted on September 9, 2015). On May 10, 2016, FERC largely denied rehearing, and a number of parties appealed to the U.S. Court of Appeals for the DC Circuit for review of the decision. On June 20, 2017, the DC Circuit denied all the appeals.

MISO Capacity Market Results

On April 14, 2015, the Midcontinent Independent System Operator (MISO) released the results of its capacity auction covering the June 2015 through May 2016 delivery year. As a result of the auction, capacity prices for the zone 4 region in downstate Illinois increased to $150 per MW per day beginning in June 2015, an increase from the prior pricing of $16.75 per MW per day that was in effect from June 2014 to May 2015. Generation had an offer that was selected in the auction. However, due to Generation's ratable hedging strategy, the results of the capacity auction have not had a material impact on Exelon's and Generation's consolidated results of operations and cash flows.

Additionally, in late May and June 2015, separate complaints were filed at the FERC by each of the State of Illinois, the Southwest Electric Cooperative, Public Citizens, Inc., and the Illinois Industrial Energy Consumers challenging the results of this MISO capacity auction for the 2015/2016 delivery in MISO delivery zone 4. The complaints allege generally that 1) the results of the capacity auction for zone 4 are not just and reasonable, 2) the results should be suspended, set for hearing and replaced with a new just and reasonable rate, 3) a refund date should be established and that 4) certain alleged behavior by one of the market participants other than Exelon or Generation, be investigated.

On October 1, 2015, FERC announced that it was conducting a non-public investigation (that does not involve Exelon or Generation) into whether market manipulation or other potential violations occurred related to the auction. On December 31, 2015, FERC issued a decision that certain of the rules governing the establishment of capacity prices in downstate Illinois are “not just and reasonable” on a prospective basis. FERC ordered that certain rules be changed prior to the April 2016 auction which set capacity prices for the 2016/2017 planning year. In response to this order, MISO filed certain rule changes with FERC. On March 18, 2016, FERC largely denied rehearing of its December 31, 2015 order. FERC continues to conduct its non-public investigation to determine if the April 2015 auction results were manipulated and, if so, whether refunds are appropriate. FERC did establish May 28, 2015, the day the first complaint was filed, as the date from which refunds (if ordered) would be calculated, and it also made clear that the findings in the December 31, 2015 order do not prejudge the investigation or related proceedings. Generation cannot predict the impact the FERC order may ultimately have on future auction results, capacity pricing or decisions related to the potential early retirement of the Clinton nuclear plant, however, such impacts could be material to Generation's future results of operations and cash flows. See Note 7 — Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on the impacts of the MISO announcement.

Subsidized Generation

The rate of expansion of subsidized generation, in the markets in which Generation's output is sold can negatively impact wholesale power prices, and in turn, Generation's results of operations.

Various states have attempted to implement or propose legislation, regulations or other policies to subsidize new generation development which may result in artificially depressed wholesale energy and capacity prices. For example, the New Jersey legislature enacted into law in January 2011, the Long Term Capacity Pilot Program Act (LCAPP). LCAPP provides eligible generators with 15-year fixed contracts for the sale of capacity in the PJM capacity market. Under LCAPP, the local utilities in New Jersey are required to pay (or receive) the difference between the price eligible generators receive in the capacity market and the price guaranteed under the 15-year contract. New Jersey ultimately selected three proposals to participate in LCAPP and build new generation in the state. In addition, on April 12, 2012, the MDPSC issued an order directing the Maryland electric utilities to enter into a 20-year contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV was required to construct an approximately 700 MW combined cycle gas turbine in Waldorf, Maryland. The CfD mandated that utilities (including BGE, Pepco and DPL) pay (or receive) the difference between CPV’s contract price and the revenues it receives for capacity and energy from clearing the unit in the PJM capacity market.

Exelon and others challenged the constitutionality and other aspects of the New Jersey legislation in federal court. The actions taken by the MDPSC were also challenged in federal court in an action to which Exelon was not a party. The federal trial courts in both the New Jersey and Maryland actions effectively invalidated the actions taken by the New Jersey legislature and the MDPSC, respectively. Each of those decisions was upheld by the U.S. Court of Appeals for the Third Circuit and the U.S. Court of Appeals for the Fourth Circuit, respectively. On April 19, 2016, the U.S. Supreme Court affirmed the decision of the U.S. Court of Appeals for the Fourth Circuit, and subsequently denied certiorari with respect to the appeal from the U.S. Court of Appeals for the Third Circuit, leaving in place that Court’s decision. The matter is now considered closed.

As required under their contracts, generator developers who were selected in the New Jersey and Maryland programs (including CPV) offered and cleared in PJM’s capacity market auctions. To the extent that the state-required customer subsidies are included under their respective contracts, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in these auctions and may continue to do so in future auctions to the detriment of Exelon. While the court decisions are positive developments, continuation of these state efforts, if successful and unabated by an effective minimum offer price rule (MOPR) for future capacity auctions, could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish programs, which could substantially impact Exelon’s position and could have a significant effect on Exelon’s financial results of operations, financial position and cash flows.

One such state is Ohio, where state-regulated utility companies FirstEnergy Ohio (FE) and AEP Ohio (AEP) initiated actions at the Public Utilities Commission of Ohio (PUCO) to obtain approval for Riders that would effectively allow these two companies to pass through to all customers in their service territories the differences between their costs and market revenues on PPAs entered into between the utility and its merchant generation affiliate for what was collectively more than 6,000MW of primarily coal-fired generation. Thus, the Riders were similar to the CfDs described above (except that the PPA Riders in Ohio would apply to existing generation facilities whereas the CfDs applied to new generation facilities). While FERC orders on April 27, 2016 largely alleviated the concerns related to the Riders by holding that the PPAs ran afoul of affiliate restrictions on FE and AEP, we continue to closely monitor developments in Ohio.

In addition, Exelon continues to monitor developments in Maryland, New Jersey, and other states and participates in stakeholder and other processes to ensure that similar state subsidies are not developed. Exelon remains active in advocating for competitive markets, while opposing policies that require taxpayers and/ or consumers to subsidize or give preferential treatment to generation providers or technologies that do not provide superior reliability or environmental benefits, or that would threaten the reliability and value of the integrated electricity grid.

Complaints at FERC Seeking to Mitigate Illinois and New York Programs Providing ZECs

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 remove the revenues it receives through a federal, state or other 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 resources. Exelon has generally opposed policies that required subsidies or give preferential treatment to generation providers or technologies that do not provide superior reliability or environmental benefits, or that would threaten the reliability and value of the integrated electricity grid. Thus, Exelon has supported a MOPR as a means of minimizing the detrimental impact of certain subsidized resources could have on capacity markets (such as the New Jersey (LCAPP) and Maryland (CfD) programs. However, in Exelon's view, MOPRs should not be applied to resources that receive compensation for providing superior reliability or environmental benefits.

On January 9, 2017, the Electric Power Supply Association (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. Both filings allege that the relevant MOPR should be expanded to also apply to existing resources receiving ZEC compensation under the New York CES and Illinois ZES programs. Exelon has 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 that have generally not been subject to a MOPR. However, if successful, for Generation's facilities in NYISO and PJM expected to receive ZEC compensation (Quad Cities, Ginna, Nine Mile Point and FitzPatrick), 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 those auctions and thus no longer receiving capacity revenues during the respective ZEC programs. Any such mitigation of these generating resources could have a material effect on Exelon's and Generation's future cash flows and results of operations. The timing of FERC's decision with respect to both proceedings is currently unknown and the outcome of these matters is currently uncertain.

Energy Demand

Modest economic growth partially offset by energy efficiency initiatives is resulting in flat to declining load growth in electricity for the utilities. There is a decrease in projected load for electricity for ComEd, PECO, BGE, and ACE, and an essentially flat projected load for electricity for DPL. ComEd, PECO, BGE, Pepco, DPL, and ACE are projecting load volumes to increase (decrease) by (0.4)%, (0.4)%, (2.3)%, (1.3)%, (1.0)%, and (3.9)% respectively, in 2017 compared to 2016.

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. The market experienced high price volatility in the first quarter of 2014 which contributed to bankruptcies and consolidations within the industry during the year. However, 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 2017 dividends of $0.3275 per share on Exelon's common stock. The first quarter 2017 dividend was paid on March 10, 2017. The dividend increased from fourth quarter 2016 amount to reflect the Board's decision to raise Exelon's dividend 2.5% each year for the next three years, beginning with the June 2016 dividend.

Exelon's Board of Directors declared the second quarter 2017 dividends of $0.3275 per share each on Exelon's common stock. The second quarter 2017 dividend was paid on June 9, 2017.

Exelon's Board of Directors declared the third quarter 2017 dividends of $0.3275 per share each on Exelon's common stock and is payable on September 8, 2017.

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 2017 and 2018. 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 June 30, 2017, the percentage of expected generation hedged for the major reportable segments is 96%-99%, 71%-74% and 39%-42% for 2017, 2018, and 2019 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 51% of Generation's uranium concentrate requirements from 2017 through 2021 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 results of operations, cash flows and financial position.

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

Tax Matters

Potential Corporate Tax Reform

The results of the November 2016 U.S. elections have introduced greater uncertainty with respect to federal tax policies. President Trump has stated that one of his top priorities is comprehensive tax reform as well as

Congressional Republicans have also advocated their intent to advance tax reform. Tax reform proposals have called for a reduction in the corporate federal income tax rate from the current 35% to as low as 15%. Other proposals provide, among other items, for the immediate deduction of capital investment expenditures and full or partial elimination of debt interest expense deductions. On July 27, 2017, the White House and Republican Congressional leaders issued a joint statement reiterating their intent to enact a comprehensive tax reform plan. The statement did not provide details, but emphasized lowering tax rates and maximizing capital expensing. It is uncertain whether and to what extent or when any changes in federal tax policies will be enacted or the transition time frame for such changes. The Utility Registrants' regulators may impose rate reductions to provide the benefit of any income tax expense reductions to customers and refund "excess" deferred income taxes previously collected through rates. The amounts and timing of any such rate changes would be subject to the discretion of the rate regulator in each specific jurisdiction. For these reasons, the Registrants cannot predict the impact any potential changes may have on their future results of operations, cash flows or financial position, and such changes could be material.

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 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 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 have been specifically identified for review are 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.

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 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, EPA is required to submit supplemental briefs on the question of whether the regulations should be remanded to the Agency or held in abeyance. On June 8, 2017, U.S. EPA submitted to the Office of Management and Budget a proposed rule entitled "Review of the Clean Power Plan." Based on filings with the D.C. Circuit, it is expect that this proposed rule will rescind the Clean Power Plan, but it is unknown whether the EPA will replace the existing unit regulation with another rule.

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. Following EPA's review and determination of its course of action for the 2015 Rule, the parties are directed to file motions within 30 days on future proceedings. On June 28, 2017, the U.S. EPA announced that it would use its authority under the Clean Air Act to extend until October 1, 2018 its deadline for promulgating initial area designations for the 2015 ozone NAAQS.

Water Quality

Section 316(b) of the Clean Water Act requires that 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 changes to the existing regulations. Those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, Fitzpatrick, Ginna, Gould Street, Handley, Mountain Creek, Mystic 7, Nine Mile Point Unit 1, Oyster Creek, Peach Bottom, Quad Cities, Riverside and Salem. See ITEM 1.—BUSINESS, "Water Quality" of the Exelon 2016 Form 10-K for further discussion.

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 classifies CCR as non-hazardous waste under RCRA. Under the regulation, CCR will continue to be regulated by most states subject to coordination with the federal regulations. Generation has previously recorded accruals consistent with state regulation for its owned coal ash sites, and as such, the regulation 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 new federal regulations 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 17 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Other Legislative and Regulatory Developments

NRC Task Force on Fukushima Daiichi Accident (Exelon and Generation).

In July 2011, an NRC Task Force formed in the aftermath of the March 11, 2011, 9.0 magnitude earthquake and ensuing tsunami, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, issued a report of its review of the accident, including tiered recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The NRC and its staff have issued orders and implementation guidance for commercial reactor licensees operating in the United States. Generation has assessed the impacts of the Tier 1 orders and information requests and will continue monitoring the additional recommendations under review by the NRC staff, both from an operational and a financial impact standpoint. Generation's current assessments are specific to the Tier 1 recommendations. In May 2017, the NRC finalized its decision that no actions are required with respect to the Tier 2 and Tier 3 recommendations. Generation will continue to engage in nuclear industry assessments and actions and obtain stakeholder input.

Employees

In January 2017, an election was held at BGE which resulted in union representation for approximately 1,400 employees. BGE and IBEW Local 410 have begun negotiations for an initial agreement which could result in some modifications to wages, hours and other terms and conditions of employment. No agreement has been finalized to date and management cannot predict the outcome of such negotiations. In April 2017, Exelon Nuclear Security successfully ratified its CBA with the SPFPA Local 238 at Quad Cities to an extension of three years. In June 2017, Exelon Nuclear Security successfully ratified its CBA with the UGSOA Local 12 at Limerick to an extension of three years.

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 2016 Form 10-K for a discussion of the estimates and judgments necessary in the Registrants' accounting for AROs, goodwill, purchase accounting, unamortized energy 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 June 30, 2017, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2016.

Results of Operations By Registrant

Net Income (Loss) Attributable to Common Shareholders by Registrant

	Three Months Ended June 30,		Favorable (Unfavorable) Variance	Six Months Ended June 30,		Favorable (Unfavorable) Variance
	2017	2016		2017	2016[a]	
Exelon	$ 80	$ 267	$ (187)	$ 1,076	$ 440	$ 636
Generation	(250)	(8)	(242)	174	302	(128)
ComEd	118	145	(27)	259	260	(1)
PECO	88	100	(12)	215	224	(9)
BGE	45	31	14	169	129	40
Pepco	43	49	(6)	101	(60)	161
DPL	19	12	7	76	(60)	136
ACE	8	3	5	36	(97)	133

(a) For Pepco, DPL and ACE, reflects that Registrant's operations for the six months ended June 30, 2016. For Exelon and Generation, includes the operations of the PHI acquired businesses for the period of March 24, 2016 through June 30, 2016.

	Successor				*Predecessor*
	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	March 24, 2016 to June 30, 2016	January 1, 2016 to March 23, 2016
PHI	$ 66	$ 52	$ 205	$ (257)	$ 19

Results of Operations — Generation

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	Favorable (Unfavorable) Variance
Operating revenues	$ 4,174	$ 3,589	$ 585	$9,061	$8,329	$ 732
Purchased power and fuel expense	2,157	1,577	(580)	4,955	4,020	(935)
Revenues net of purchased power and fuel expense[(a)]	2,017	2,012	5	4,106	4,309	(203)
Other operating expenses						
Operating and maintenance	2,010	1,530	(480)	3,497	2,997	(500)
Depreciation and amortization	334	408	74	637	697	60
Taxes other than income	140	118	(22)	282	244	(38)
Total other operating expenses	2,484	2,056	(428)	4,416	3,938	(478)
Gain on sales of assets	—	31	(31)	4	31	(27)
Bargain purchase gain	—	—	—	226	—	226
Operating (loss) income	(467)	(13)	(454)	(80)	402	(482)
Other income and (deductions)						
Interest expense, net	(129)	(99)	(30)	(228)	(196)	(32)
Other, net	181	117	64	440	210	230
Total other income and (deductions)	52	18	34	212	14	198
Income before income taxes	(415)	5	(420)	132	416	(284)
Income taxes	(158)	(31)	127	(31)	120	151
Equity in losses of unconsolidated affiliates	(9)	(8)	(1)	(19)	(11)	(8)
Net (loss) income	(266)	28	(294)	144	285	(141)
Net (loss) income attributable to noncontrolling interests	(16)	36	52	(30)	(17)	13
Net (loss) income attributable to membership interest	$ (250)	$ (8)	$ (242)	$ 174	$ 302	$ (128)

(a) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense 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.

Net Income (Loss) Attributable to Membership Interest

Three Months Ended June 30, 2017 Compared to three months ended June 30, 2016. Generation's Net loss attributable to membership interest for the three months ended June 30, 2017 increased compared to the same period in 2016, primarily due to higher Operating and maintenance expenses, the absence of 2016 gain on sales of assets and higher interest expense, partially offset by higher Revenue net of purchased power and fuel expense, lower Depreciation and amortization expenses, higher other income, and higher income tax benefits. The increase in Operating and maintenance expenses primarily related to the impairment of EGTP assets held for sale. The increase in interest expense is primarily due to higher outstanding debt. The increase in Revenue net of purchased power and fuel expense primarily relates to decreased mark-to-market losses in 2017 compared to 2016, Zero Emission Credit revenue due to the impact of the New York Clean Energy Standard, increased nuclear volumes due to the acquisition of the FitzPatrick nuclear facility and decreased fuel prices, almost entirely offset by the conclusion of the Ginna Reliability Support Services Agreement, lower realized energy prices and lower optimization in Generation's natural gas portfolio. The decrease in Depreciation and amortization is primarily due to lower accelerated depreciation and amortization as a result of the 2017 decision to early retire the TMI nuclear facility compared to the previous decision in 2016 to early retire Clinton and Quad Cities nuclear facilities. The increase in other income is primarily due to the change in realized and unrealized gains and losses on NDT funds. The increase in income tax benefits is primarily due to higher operating losses.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. Generation's Net income attributable to membership interest for the six months ended June 30, 2017 decreased compared to the same period in 2016, primarily due to lower Revenue net of purchased power and fuel expense, higher Operating and maintenance expenses, and higher interest expense, partially offset by lower Depreciation and amortization, a bargain purchase gain associated with the acquisition of FitzPatrick, and higher other income. The decrease in Revenue net of purchased power and fuel expense primarily relates to the impacts of declining natural gas prices and lower optimization in Generation's natural gas portfolio, the conclusion of the Ginna Reliability Support Services Agreement, lower realized energy prices, decreased capacity prices, and increased market-to-market losses in 2017 compared to 2016, partially offset by Zero Emission Credit revenue due to the impact of the New York Clean Energy Standard and the absence of inventory write downs in 2017. The increase in operating and maintenance expenses primarily relates to the impairment of EGTP assets held for sale. The increase in interest expense is primarily due to higher outstanding debt. The decrease in Depreciation and amortization is primarily due to lower accelerated depreciation and amortization as a result of the 2017 decision to early retire the TMI nuclear facility compared to the previous decision in 2016 to early retire Clinton and Quad Cities nuclear facilities. The bargain purchase gain is the result of the FitzPatrick acquisition in Q1 2017. The increase in other income is primarily due to increased unrealized gains on NDT funds in 2017 compared to 2016.

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. Descriptions of each of Generation's six 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, which includes portions of Illinois, Pennsylvania, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO, excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.

- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Power Regions:
  - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes AESO, OIESO and the Canadian portion of MISO.

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 Generation's overall operating revenues or results of operations. Further, the following activities are not allocated to a region, and are reported in Other: amortization of certain intangible assets relating to commodity contracts recorded at fair value from mergers and acquisitions; accelerated nuclear fuel amortization associated with nuclear decommissioning; and other miscellaneous revenues.

Generation evaluates the operating performance of its electric business activities using the measure of Revenue net of purchased power and fuel expense, which is a non-GAAP measurement. 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 owned generation and fuel costs associated with tolling agreements.

For the three and six months ended June 30, 2017 and 2016, Generation's Revenue net of purchased power and fuel expense by region were as follows:

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Variance	% Change	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	Variance	% Change
Mid-Atlantic[a]	$ 783	$ 828	$ (45)	(5.4)%	$1,557	$1,669	$ (112)	(6.7)%
Midwest[b]	728	728	—	—%	1,443	1,449	(6)	(0.4)%
New England	147	110	37	33.6%	257	191	66	34.6%
New York[d]	230	267	(37)	(13.9)%	385	395	(10)	(2.5)%
ERCOT	70	77	(7)	(9.1)%	138	138	—	—%
Other Power Regions	90	96	(6)	(6.3)%	152	174	(22)	(12.6)%
Total electric revenue net of purchased power and fuel expense	2,048	2,106	(58)	(2.8)%	3,932	4,016	(84)	(2.1)%
Proprietary Trading	7	4	3	75.0%	7	6	1	16.7%
Mark-to-market (losses) gains	(184)	(304)	120	(39.5)%	(233)	(201)	(32)	15.9%
Other[c]	146	206	(60)	(29.1)%	400	488	(88)	(18.0)%
Total revenue net of purchased power and fuel expense	$ 2,017	$ 2,012	$ 5	0.2%	$4,106	$4,309	$ (203)	(4.7)%

(a) Results of transactions with PECO and BGE are included in the Mid-Atlantic region. Results of transactions with Pepco, DPL, and ACE are included in the Mid-Atlantic region beginning on March 24, 2016, the day after the PHI merger was completed.

(b) Results of transactions with ComEd are included in the Midwest region.

(c) Other represents activities not allocated to a region. See text above for a description of included activities. Includes amortization of intangible assets related to commodity contracts recorded at fair value of a $20 million decrease and a $12 million decrease to revenue net of purchased power and fuel expense for the three months ended June 30, 2017 and 2016, respectively, and amortization of intangible assets related to commodity contracts recorded at fair value of a $22 million decrease and a $7 million increase to revenue net of purchased power and fuel expense for the six months ended June 30, 2017 and 2016, respectively.

(d) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

Generation's supply sources by region are summarized below:

Supply source (GWh)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Variance	% Change	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	Variance	% Change
Nuclear generation								
Mid-Atlantic[(a)]	15,246	15,224	22	0.1%	31,790	31,432	358	1.1%
Midwest	22,592	23,001	(409)	(1.8)%	45,061	46,663	(1,602)	(3.4)%
New York[(a)(d)]	6,227	4,228	1,999	47.3%	10,718	9,160	1,558	17.0%
Total Nuclear Generation	44,065	42,453	1,612	3.8%	87,569	87,255	314	0.4%
Fossil and Renewables								
Mid-Atlantic	899	685	214	31.2%	1,734	1,583	151	9.5%
Midwest	417	324	93	28.7%	835	773	62	8.0%
New England	1,925	2,016	(91)	(4.5)%	4,002	3,940	62	1.6%
New York	1	1	—	—%	2	2	—	—%
ERCOT	2,315	1,879	436	23.2%	3,684	3,255	429	13.2%
Other Power Regions	2,084	1,995	89	4.5%	3,507	4,142	(635)	(15.3)%
Total Fossil and Renewables	7,641	6,900	741	10.7%	13,764	13,695	69	0.5%
Purchased Power								
Mid-Atlantic	2,901	3,131	(230)	(7.3)%	6,299	6,886	(587)	(8.5)%
Midwest	413	688	(275)	(40.0)%	801	1,394	(593)	(42.5)%
New England	4,343	3,782	561	14.8%	9,407	7,937	1,470	18.5%
New York	—	—	—	—%	28	—	28	—%
ERCOT	1,871	2,259	(388)	(17.2)%	4,525	4,553	(28)	(0.6)%
Other Power Regions	3,507	3,879	(372)	(9.6)%	6,375	6,479	(104)	(1.6)%
Total Purchased Power	13,035	13,739	(704)	(5.1)%	27,435	27,249	186	0.7%
Total Supply/Sales by Region[(b)]								
Mid-Atlantic[(c)]	19,046	19,040	6	—%	39,823	39,901	(78)	(0.2)%
Midwest[(c)]	23,422	24,013	(591)	(2.5)%	46,697	48,830	(2,133)	(4.4)%
New England	6,268	5,798	470	8.1%	13,409	11,877	1,532	12.9%
New York	6,228	4,229	1,999	47.3%	10,748	9,162	1,586	17.3%
ERCOT	4,186	4,138	48	1.2%	8,209	7,808	401	5.1%
Other Power Regions	5,591	5,874	(283)	(4.8)%	9,882	10,621	(739)	(7.0)%
Total Supply/Sales by Region	64,741	63,092	1,649	2.6%	128,768	128,199	569	0.4%

(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) Excludes physical proprietary trading volumes of 2,312 GWh and 1,289 GWh for the three months ended June 30, 2017 and 2016, respectively, and 4,162 GWh and 2,509 GWh for the six months ended June 30, 2017 and 2016.

(c) Includes affiliate sales to PECO and BGE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region. As a result of the PHI Merger, includes affiliate sales to Pepco, DPL and ACE in the Mid-Atlantic region beginning on March 24, 2016.

(d) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

Mid-Atlantic

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. The $45 million decrease in Revenue net of purchased power and fuel expense in the Mid-Atlantic primarily reflects lower realized energy prices and decreased capacity prices.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. The $112 million decrease in Revenue net of purchased power and fuel expense in the Mid-Atlantic primarily reflects lower realized energy prices and decreased capacity prices, partially offset by the absence of oil inventory write-downs in 2017 and decreased nuclear outage days.

Midwest

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. The immaterial change in Revenue net of purchased power and fuel expense in the Midwest primarily reflects increased nuclear outage days, offset by decreased nuclear fuel prices.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. The $6 million decrease in Revenue net of purchased power and fuel expense in the Midwest primarily reflects increased nuclear outage days and decreased capacity prices, partially offset by decreased nuclear fuel prices.

New England

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. The $37 million increase in Revenue net of purchased power and fuel expense in New England was driven by increased capacity prices.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. The $66 million increase in Revenue net of purchased power and fuel expense in New England was driven by increased capacity prices and the higher realized energy prices.

New York

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. The $37 million decrease in Revenue net of purchased power and fuel expense in New York was primarily due to the conclusion of the Ginna Reliability Support Service Agreement, partially offset by Zero Emission Credit revenue due to the impact of the New York Clean Energy Standard and the acquisition of Fitzpatrick.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. The $10 million decrease in Revenue net of purchased power and fuel expense in New York was primarily due to the conclusion of the Ginna Reliability Support Service Agreement, partially offset by Zero Emission Credit revenue due to the impact of the New York Clean Energy Standard and the acquisition of Fitzpatrick.

ERCOT

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. The $7 million decrease in Revenue net of purchased power and fuel expense in ERCOT was primarily due to lower realized energy prices.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. There was an immaterial change in Revenue net of purchased power and fuel expense in ERCOT.

Other Power Regions

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. The $6 million decrease in Revenue net of purchased power and fuel expense in Other Power Regions was primarily due to lower realized energy prices.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. The $22 million decrease in Revenue net of purchased power and fuel expense in Other Power Regions was primarily due to lower realized energy prices.

Proprietary Trading

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. The $3 million increase in Revenue net of purchased power and fuel expense in Proprietary Trading was primarily due to congestion activity.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. The $1 million increase in Revenue net of purchased power and fuel expense in Proprietary Trading was primarily due to congestion activity.

Mark-to-market

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. Mark-to-market losses on economic hedging activities were $184 million for the three months ended June 30, 2017 compared to losses of $304 million for the three months ended June 30, 2016. See Notes 8 — Fair Value of Financial Assets and Liabilities and 9 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. Mark-to-market losses on economic hedging activities were $233 million for the six months ended June 30, 2017 compared to losses of $201 million for the six months ended June 30, 2016. See Notes 8 — Fair Value of Financial Assets and Liabilities and 9 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Other

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. The $60 million decrease in other revenue net of purchased power and fuel was primarily due to lower optimization in Generation's natural gas portfolio and amortization of energy contracts recorded at fair value associated with prior acquisitions.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. The $88 million decrease in other revenue net of purchased power and fuel was primarily due to the impacts of declining natural gas prices and lower optimization in Generation's natural gas portfolio and amortization of energy contracts recorded at fair value associated with prior acquisitions, partially offset by revenue related to the inclusion of Pepco Energy Services results in 2017 and revenue related to energy efficiency projects.

Nuclear Fleet Capacity Factor

The following table presents nuclear fleet operating data for the three and six months ended June 30, 2017 as compared to the same period in 2016, for the Generation-operated plants. 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 June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Nuclear fleet capacity factor[(a)]	90.9%	92.3%	92.4%	94.1%
Refueling outage days[(a)]	125	87	220	157
Non-refueling outage days[(a)]	12	21	20	31

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC. Reflects ownership percentage of stations operated by Exelon. Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. The nuclear fleet capacity factor decreased primarily due to more refueling outage days and was partially offset by fewer non-refueling outage days, excluding Salem outages, during the three months ended June 30, 2017 compared to the same period in 2016.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. The nuclear fleet capacity factor decreased primarily due to more refueling outage days and was partially offset by fewer non-refueling outage days, excluding Salem outages, during the six months ended June 30, 2017 compared to the same period in 2016.

Operating and Maintenance

The changes in Operating and maintenance expense for the three and six months ended June 30, 2017 as compared to the same period in 2016, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)[(a)]	Six Months Ended June 30, Increase (Decrease)[(a)]
Labor, other benefits, contracting, materials[(b)]	$ 12	$ 85
Nuclear refueling outage costs, including the co-owned Salem plants[(c)]	71	99
Corporate allocations	6	10
Merger and integration costs[(d)]	15	40
Merger commitments	—	(3)
Plant retirements and divestitures[(e)]	(56)	(56)
Cost management program	1	(12)
Long-lived asset impairments[(f)]	383	263
Pension and non-pension postretirement benefits expense	3	—
Allowance for uncollectible accounts	16	19
Accretion expense[(g)]	12	18
Other	17	37
Increase in operating and maintenance expense	$ 480	$ 500

(a) The 2017 financial results include Generation's acquisition of the FitzPatrick nuclear generating station from March 31, 2017.

(b) Reflects an increase of labor, other benefits, contracting and materials costs primarily due to the inclusion of Pepco Energy Services results for the six months ended June 30, 2017 compared to the period March 24, 2016 to June 30, 2016, increased contracting costs related to energy efficiency projects for the six months ended June 30, 2017 compared to the same period in 2016 and the inclusion of FitzPatrick beginning on March 31, 2017.
(c) Primarily reflects an increase in the number of nuclear outage days in 2017.
(d) Reflects certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities related to the PHI and FitzPatrick acquisitions.
(e) Represents the announcement of the early retirement of Generation's TMI nuclear facility in 2017 compared to the previous decision to early retire Generation's Clinton and Quad Cities nuclear facilities in 2016.
(f) Primarily reflects charges to earnings related to impairments as a result of the EGTP assets held for sale in 2017 and impairment of Upstream assets and certain wind projects in 2016.
(g) Reflects the impact of increased accretion expenses primarily due to the acquisition of FitzPatrick on March 31, 2017.

Depreciation and Amortization

Depreciation and amortization expense for the three and six months ended June 30, 2017 compared to the three and six months ended June 30, 2016 decreased primarily as a result of the 2017 decision to early retire the TMI nuclear facility compared to the previous decision in 2016 to early retire Clinton and Quad Cities nuclear facilities.

Taxes Other Than Income

Taxes other than income taxes, which can vary period to period, include non-income municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income for the three and six months ended June 30, 2017 compared to the three and six months ended June 30, 2016 increased primarily as a result of the addition of FitzPatrick and increased gross receipts tax expense.

Gain on Sales of Assets

Gain on sales of assets for the three and six months ended June 30, 2017 compared to the three and six months ended June 30, 2016 decreased primarily due to the gain associated with Generation's sale of the New Boston generating site in 2016.

Bargain Purchase Gain

Bargain purchase gain for the three and six months ended June 30, 2017 compared to the three and six months ended June 30, 2016 increased as a result of the gain associated with the Fitzpatrick acquisition. Refer to Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information.

Interest Expense, net

Interest expense, net for the three and six months ended June 30, 2017 compared to the three and six months ended June 30, 2016 increased primarily due to higher outstanding debt.

Other, Net

Other, net for the three and six months ended June 30, 2017 compared to the three and six months ended June 30, 2016 increased primarily due to the change in the realized and unrealized gains and losses related to NDT funds of Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $92 million and $26 million for the three months ended June 30, 2017 and 2016, respectively, and $37 million and $46 million for the six months ended June 30, 2017 and 2016, respectively, related to the contractual elimination of income tax expense (benefit) associated with the NDT funds of the Regulatory Agreement Units. Refer to Note 12 — Nuclear Decommissioning of the Combined Notes to the Consolidated Financial Statements for additional information regarding NDT funds.

The following table provides unrealized and realized gains and losses on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for the three and six months ended June 30, 2017 and 2016:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Net unrealized gains on decommissioning trust funds	$ 70	$ 48	$ 235	$ 100
Net realized gains on sale of decommissioning trust funds	40	12	49	14

Equity in Losses of Unconsolidated Affiliates

Equity in losses of unconsolidated affiliates for the three and six months ended June 30, 2017 compared to the three and six ended June 30, 2016 remained relatively stable.

Effective Income Tax Rate

Generation's effective income tax rate was 38.1% and (620.0)% for the three months ended June 30, 2017 and 2016, respectively. Generation's effective income tax rate was (23.5)% and 28.8% for the six months ended June 30, 2017 and 2016, respectively. See Note 11 — Income Taxes of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in the effective income tax rate.

Results of Operations — ComEd

	Three Months Ended June 30,		Favorable (Unfavorable) Variance	Six Months Ended June 30,		Favorable (Unfavorable) Variance
	2017	2016		2017	2016	
Operating revenues	$ 1,357	$ 1,286	$ 71	$ 2,656	$ 2,535	$ 121
Purchased power expense	378	339	(39)	713	686	(27)
Revenues net of purchased power expense[(a)(b)]	979	947	32	1,943	1,849	94
Other operating expenses						
Operating and maintenance	377	368	(9)	747	736	(11)
Depreciation and amortization	211	190	(21)	419	379	(40)
Taxes other than income	72	65	(7)	144	141	(3)
Total other operating expenses	660	623	(37)	1,310	1,256	(54)
Gain on sales of assets	—	—	—	—	5	(5)
Operating income	319	324	(5)	633	598	35
Other income and (deductions)						
Interest expense, net	(101)	(91)	(10)	(185)	(177)	(8)
Other, net	4	3	1	8	7	1
Total other income and (deductions)	(97)	(88)	(9)	(177)	(170)	(7)
Income before income taxes	222	236	(14)	456	428	28
Income taxes	104	91	(13)	197	168	(29)
Net income	$ 118	$ 145	$ (27)	$ 259	$ 260	$ (1)

(a) ComEd evaluates its operating performance using the measure of Revenue net of purchased power expense. ComEd believes that Revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of Revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense 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.

(b) For regulatory recovery mechanisms, including ComEd's electric distribution and transmission formula rates, and riders, revenues increase and decrease i) as fully recoverable costs fluctuate (with no impact on net earnings), and ii) pursuant to changes in rate base, capital structure and ROE (which impact net earnings).

Net Income

Three months ended June 30, 2017 Compared to Three months ended June 30, 2016. ComEd's Net income for the three months ended June 30, 2017 was lower than the same period in 2016, primarily due to additional tax and interest recorded in the second quarter of 2017 relating to to Exelon's like-kind exchange tax position and favorable weather conditions in the second quarter of 2016, partially offset by increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment and higher allowed electric distribution ROE).

Six months ended June 30, 2017 Compared to Six months ended June 30, 2016. ComEd's Net income for the six months ended June 30, 2017 was relatively consistent with the same period in 2016, primarily due to additional tax and interest recorded in the second quarter of 2017 relating to to Exelon's like-kind exchange tax position, mostly offset by increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment and higher allowed electric distribution ROE).

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 is permitted to recover electricity, REC, and ZEC procurement costs from retail customers without mark-up. Therefore, these costs have no impact on Revenue net of purchased power expense. See Note 3 — Regulatory Matters of the Exelon 2016 Form 10-K for additional information on ComEd's electricity procurement process.

All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact ComEd's volume of deliveries, but do affect ComEd's Operating revenues related to supplied energy, which is fully offset in Purchased power expense. Therefore, customer choice programs have no impact on Revenue net of purchased power expense.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three and six months ended June 30, 2017 and 2016, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Electric	71%	73%	71%	73%

Retail customers purchasing electric generation from competitive electric generation suppliers at June 30, 2017 and 2016 consisted of the following:

	June 30, 2017		June 30, 2016	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	1,382,600	35%	1,605,100	41%

The changes in ComEd's Revenue net of purchased power expense for the three and six months ended June 30, 2017, compared to the same period in 2016 consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)	Six Months Ended June 30, 2017 Increase (Decrease)
Weather[(a)]	$ (11)	$ (3)
Volume[(a)]	(5)	(6)
Electric distribution revenue	36	60
Transmission revenue	17	34
Energy efficiency revenue	1	1
Regulatory required programs	(5)	15
Uncollectible accounts recovery, net	(1)	(3)
Pricing and customer mix[(a)]	2	(1)
Other	(2)	(3)
Total increase	$ 32	$ 94

(a) These changes only reflect the 2016 impacts of weather, volume, and pricing and customer mix. As further described below, pursuant to the revenue decoupling provision in FEJA, ComEd began recording an adjustment to revenue in the first quarter of 2017 to eliminate the favorable or unfavorable impacts associated with variations in delivery volumes associated with above or below normal weather, number of customers or usage per customer.

Revenue Decoupling. The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as "favorable weather conditions" because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand.

Under EIMA, ComEd's electric distribution formula rate provided for an adjustment to future billings if its earned ROE fell outside a 50 bps collar of its allowed ROE, which partially eliminated the impacts of weather and load on ComEd's revenue. As allowed under FEJA, ComEd will revise its electric distribution formula rate to eliminate the ROE collar beginning with the reconciliation filed in 2018 for the 2017 calendar year. Elimination of the ROE collar effectively offsets the favorable or unfavorable impacts to Operating revenues associated with variations in delivery volumes associated with above or below normal weather, numbers of customers or usage per customer. ComEd began recognizing the impacts of this change beginning in the first quarter of 2017. During the three and six months ended June 30, 2017, ComEd recorded an increase to Electric distribution revenues of approximately $19 million and $36 million, respectively, to eliminate the unfavorable weather and load impacts.

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 ComEd's service territory with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd's service territory for the three and six months ended June 30, 2017 and 2016, consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended June 30,	2017	2016	Normal	2017 vs. 2016	2017 vs. Normal
Heating Degree-Days	577	755	734	(23.6)%	(21.4)%
Cooling Degree-Days	263	290	241	(9.3)%	9.1%
Six Months Ended June 30,					
Heating Degree-Days	3,227	3,655	3,875	(11.7)%	(16.7)%
Cooling Degree-Days	263	290	241	(9.3)%	9.1%

Electric Distribution Revenue. EIMA 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 EIMA, electric distribution revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, and allowed ROE. ComEd's allowed ROE is the annual average rate on 30-year treasury notes plus 580 basis points. In addition, ComEd's allowed ROE is subject to reduction if ComEd does not deliver the reliability and customer service benefits to which it has committed over the ten-year life of the investment program. During the three and six months ended June 30, 2017, electric distribution revenue increased primarily due to revenue decoupling impacts (as described above), increased capital investment, increased Depreciation expense, and higher allowed ROE due to an increase in treasury rates, as compared to the same period in 2016. See Depreciation and amortization expense discussions below, and Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered and the highest daily peak load, which is updated annually in January based on the prior calendar year. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. For the three and six months ended June 30, 2017, ComEd recorded increased transmission revenue due to increased capital investment, higher Depreciation expense and increased highest daily peak load as compared to the same period in 2016. See Operating and maintenance expense below and Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Energy Efficiency Revenue. Beginning June 1, 2017, 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. ComEd's allowed ROE is the annual average rate on 30-year treasury notes plus 580 basis points. Beginning January 1, 2018, ComEd's allowed ROE is subject to a maximum downward or upward adjustment of 200 basis points if ComEd's cumulative persisting annual MWh savings falls short of or exceeds specified percentage benchmarks of its annual incremental savings goal. See Depreciation and amortization expense discussions below, and Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in Operating revenues collected under approved rate riders to recover costs incurred for regulatory programs such as ComEd's energy efficiency and demand response and purchased power administrative costs. The riders are designed to provide full and current cost recovery. An equal and offsetting amount has been included in Operating and maintenance expense. See Operating and maintenance expense discussion below for additional information on included programs.

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

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, recoveries of environmental costs associated with MGP sites, and recoveries of energy procurement costs.

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Operating and Maintenance Expense

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Increase (Decrease)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	Increase (Decrease)
Operating and maintenance expense — baseline	$ 334	$ 320	$ 14	$ 645	$ 649	$ (4)
Operating and maintenance expense — regulatory required programs[(a)]	43	48	$ (5)	102	87	15
Total operating and maintenance expense	$ 377	$ 368	$ 9	$ 747	$ 736	$ 11

(a) Operating and maintenance expense for regulatory required programs are costs for various legislative and/or regulatory programs that 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.

The increase in Operating and maintenance expense for the three and six months ended June 30, 2017 compared to the same period in 2016, consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)	Six Months Ended June 30, 2017 Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ (1)	$ (6)
Pension and non-pension postretirement benefits expense	1	1
Storm-related costs	7	—
Uncollectible accounts expense — provision[(a)]	(2)	(5)
Uncollectible accounts expense — recovery, net[(a)]	1	2
BSC costs	14	14
Other	(6)	(10)
	14	(4)
Regulatory required programs		
Energy efficiency and demand response programs[(b)]	(5)	15
Increase in operating and maintenance expense	$ 9	$ 11

(a) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. During the three and six months ended June 30, 2017, ComEd recorded a net decrease in Operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery. An equal and offsetting decrease has been recognized in Operating revenues for the period presented.

(b) Beginning on June 1, 2017, ComEd is deferring energy efficiency costs as a regulatory asset that will be recovered through the energy efficiency over the weighted average useful life of the related energy efficiency measures.

Depreciation and Amortization Expense

The increase in Depreciation and amortization expense during the three and six months ended June 30, 2017, compared to the same period in 2016, consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)	Six Months Ended June 30, 2017 Increase (Decrease)
Depreciation expense[a]	$ 16	$ 32
Regulatory asset amortization[b]	2	1
Other	3	7
Total increase	$ 21	$ 40

(a) Primarily reflects ongoing capital expenditures for the three and six months ended June 30, 2017.
(b) Beginning in June 2017, includes amortization of ComEd's energy efficiency regulatory asset.

Taxes Other Than Income

Taxes other than income, which can vary year to year, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income taxes increased during the three and six months ended June 30, 2017, compared to the same period in 2016, due to a reduction in the state utility tax in 2016, which is completely offset above in Operating revenues.

Gain on Sales of Assets

The decrease in Gain on sales of assets during the three and six months ended June 30, 2017, compared to the same period in 2016, is primarily due to the sale of land during March 2016.

Interest Expense, Net

The changes in interest expense, net, for the three and six months ended June 30, 2017, compared to the same period in 2016, consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)	Six Months Ended June 30, 2017 Increase (Decrease)
Interest expense related to uncertain tax positions[a]	$ 9	$ 7
Interest expense on debt (including financing trusts)	2	4
Other	(1)	(3)
Decrease in interest expense, net	$ 10	$ 8

(a) Primarily reflects additional interest recorded in the second quarter of 2017 related to Exelon's like-kind exchange tax position.

Other, Net

Other, net, remained relatively consistent during the three and six months ended June 30, 2017, compared to the same period in 2016.

Effective Income Tax Rate

ComEd's effective income tax rate was 46.8% and 38.6% for the three months ended June 30, 2017 and 2016, respectively. ComEd's effective income tax rate was 43.2% and 39.3% for the six months ended June 30, 2017 and 2016, respectively. The increases in the effective income tax rate for the three and six months ended June 30, 2017 as compared to the same period in 2016 are due to additional tax recorded related to Exelon's like-kind exchange tax position. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

ComEd Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	% Change	Weather-Normal % Change	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	% Change	Weather-Normal % Change
Retail Deliveries[(a)]								
Residential	5,919	6,349	(6.8)%	(3.0)%	12,160	12,725	(4.4)%	(1.3)%
Small commercial & industrial	7,437	7,735	(3.9)%	(2.7)%	15,146	15,615	(3.0)%	(1.8)%
Large commercial & industrial	6,798	6,736	0.9%	1.5%	13,480	13,493	(0.1)%	0.5%
Public authorities & electric railroads	282	277	1.8%	1.8%	625	639	(2.2)%	(1.1)%
Total retail deliveries	20,436	21,097	(3.1)%	(1.4)%	41,411	42,472	(2.5)%	(0.9)%

Number of Electric Customers	As of June 30, 2017	As of June 30, 2016
Residential	3,605,731	3,570,528
Small commercial & industrial	375,976	372,354
Large commercial & industrial	2,009	1,972
Public authorities & electric railroads	4,785	4,749
Total	3,988,501	3,949,603

Electric Revenue	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	% Change	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	% Change
Retail Sales[(a)]						
Residential	$ 656	$ 625	5.0%	$1,283	$1,232	4.1%
Small commercial & industrial	347	329	5.5%	680	651	4.5%
Large commercial & industrial	123	116	6.0%	231	224	3.1%
Public authorities & electric railroads	11	11	—%	24	23	4.3%
Total retail	1,137	1,081	5.2%	2,218	2,130	4.1%
Other revenue[(b)]	220	205	7.3%	438	405	8.1%
Total electric revenue[(c)]	$ 1,357	$ 1,286	5.5%	$2,656	$2,535	4.8%

(a) Reflects delivery revenue and volume from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.

(b) Other revenue primarily includes transmission revenue from PJM. Other revenue also includes rental revenue, revenue related to late payment charges, revenue from other utilities for mutual assistance programs and recoveries of remediation costs associated with MGP sites.

(c) Includes operating revenues from affiliates totaling $3 million and $3 million for the three and six months ended June 30, 2017 and 2016, and $9 million and $8 million for the six months ended June 30, 2017 and 2016, respectively.

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Results of Operations — PECO

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	Favorable (Unfavorable) Variance
Operating revenues	$ 630	$ 664	$ (34)	$ 1,426	$ 1,505	$ (79)
Purchased power and fuel expense	197	217	20	484	537	53
Revenues net of purchased power and fuel expense[(a)]	433	447	(14)	942	968	(26)
Other operating expenses						
Operating and maintenance	190	190	—	398	405	7
Depreciation and amortization	71	67	(4)	141	134	(7)
Taxes other than income	35	38	3	74	80	6
Total other operating expenses	296	295	(1)	613	619	6
Operating income	137	152	(15)	329	349	(20)
Other income and (deductions)						
Interest expense, net	(31)	(31)	—	(62)	(62)	—
Other, net	2	2	—	3	4	(1)
Total other income and (deductions)	(29)	(29)	—	(59)	(58)	(1)
Income before income taxes	108	123	(15)	270	291	(21)
Income taxes	20	23	3	55	67	12
Net income	$ 88	$ 100	$ (12)	$ 215	$ 224	$ (9)

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not presentations defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. PECO's Net income decreased from the same period in 2016, primarily due to lower Revenues net of purchased power and fuel from changes in electric volumes as well as higher depreciation and amortization expense as a result of increased capital expenditures.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. PECO's Net income decreased from the same period in 2016, primarily due to lower Revenues net of purchased power and fuel from changes in electric volumes as well as higher depreciation and amortization expense as a result of increased capital expenditures.

Revenues Net of Purchased Power and Fuel Expense

Electric and natural gas revenue and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments at least quarterly that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with the PAPUC's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and natural gas revenue net of purchased power and fuel expense.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The customers' choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and natural gas revenue net of purchased power and fuel expense.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and six months ended June 30, 2017 and 2016, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Electric	73%	72%	71%	70%
Natural Gas	29%	28%	26%	26%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at June 30, 2017 and 2016 consisted of the following:

	June 30, 2017		June 30, 2016	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	581,600	36%	576,300	36%
Natural Gas	82,000	16%	81,100	16%

The changes in PECO's Operating revenues net of purchased power and fuel expense for the three and six months ended June 30, 2017 compared to the same period in 2016 consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)			Six Months Ended June 30, 2017 Increase (Decrease)		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Weather	$ 1	$ (4)	$ (3)	$ 3	$ (3)	$ —
Volume	(6)	3	(3)	(11)	3	(8)
Pricing	—	—	—	(2)	—	(2)
Regulatory required programs	(9)	—	(9)	(18)	—	(18)
Other	1	—	1	3	(1)	2
Total decrease	$ (13)	$ (1)	$ (14)	$ (25)	$ (1)	$ (26)

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 June 30, 2017 compared to the same period in 2016, Operating revenue net of purchased power was relatively consistent. Operating revenue net of fuel expense decreased due to unfavorable second quarter weather conditions. During the six months ended June 30, 2017 compared to the same period in 2016, Operating revenue net of purchased power and fuel expense was relatively consistent.

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Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the three and six months ended June 30, 2017 compared to the same periods in 2016 and normal weather consisted of the following:

Heating and Cooling Degree-Days Three Months Ended June 30,	2017	2016	Normal	% Change 2017 vs. 2016	% Change 2017 vs. Normal
Heating Degree-Days	329	469	463	(29.9)%	(28.9)%
Cooling Degree-Days	415	391	348	6.1%	19.3%
Six Months Ended June 30,					
Heating Degree-Days	2,423	2,606	2,939	(7.0)%	(17.6)%
Cooling Degree-Days	415	396	348	4.8%	19.3%

Volume. The decrease in Operating revenue net of purchased power related to delivery volume, exclusive of the effects of weather, for the three and six months ended June 30, 2017 compared to the same period in 2016, primarily reflects the impacts of energy efficiency initiatives on customer usage partially offset by moderate economic and customer growth, as well as a shift in the volume profile across classes from residential to commercial and industrial classes. Operating revenue net of fuel expense for the three and six months ended June 30, 2017 compared to the same period in 2016 remained relatively consistent.

Pricing. Operating revenues net of purchased power and fuel expense as a result of pricing for the three and six months ended June 30, 2017 compared to the same period in 2016 remained relatively consistent.

Regulatory Required Programs. This represents the change in Operating revenue collected under approved riders to recover costs incurred for regulatory programs such as 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. Refer to the Operating and maintenance expense discussion below for additional information on included programs.

Other. Other revenue, which can vary period to period, primarily includes wholesale transmission revenue, rental revenue, revenue related to late payment charges and assistance provided to other utilities through mutual assistance programs.

Operating and Maintenance Expense

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Increase (Decrease)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	Increase (Decrease)
Operating and maintenance expense — baseline	$ 174	$ 165	$ 9	$ 370	$ 361	$ 9
Operating and maintenance expense — regulatory required programs[(a)]	16	25	(9)	28	44	(16)
Total operating and maintenance expense	$ 190	$ 190	$ —	$ 398	$ 405	$ (7)

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenue.

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The changes in Operating and maintenance expense for the three and six months ended June 30, 2017 compared to the same period in 2016, consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)		Six Months Ended June 30, 2017 Increase (Decrease)	
Baseline				
Labor, other benefits, contracting and materials	$	4	$	7
Storm-related costs		(2)		(4)
Pension and non-pension postretirement benefits expense		(1)		(2)
BSC costs		4		1
Uncollectible accounts expense		(2)		(1)
Other		6		8
		9		9
Regulatory Required Programs				
Energy efficiency		(8)		(16)
Other		(1)		—
		(9)		(16)
Total decrease	$	—	$	(7)

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for the three months ended June 30, 2017 compared to the same period in 2016, consisted of an increase of $4 million. Depreciation and amortization expense for the six months ended June 30, 2017 compared to the same period in 2016, consisted of an increase of $7 million.

Taxes Other Than Income

Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income decreased for the three and six months ended June 30, 2017 compared to the same period in 2016 due to a decrease in gross receipts tax driven by decreases in electric revenue.

Interest Expense, Net

Interest expense, net for the three and six months ended June 30, 2017 remained consistent compared to the same period in 2016.

Other, Net

Other, net for the three and six months ended June 30, 2017 remained consistent compared to the same period in 2016.

Effective Income Tax Rate

PECO's effective income tax rate was 18.5% and 18.7% for the three months ended June 30, 2017 and 2016, respectively, and 20.4% and 23.0% for the six months ended June 30, 2017 and 2016, respectively. See Note 11 — Income Taxes of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in effective income tax rate.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	% Change	Weather - Normal % Change	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	% Change	Weather - Normal % Change
Retail Deliveries[a]								
Residential	2,809	2,909	(3.4)%	(3.3)%	6,187	6,324	(2.2)%	(2.2)%
Small commercial & industrial	1,914	1,887	1.4%	0.9%	3,890	3,912	(0.6)%	(1.1)%
Large commercial & industrial	3,830	3,770	1.6%	0.4%	7,456	7,364	1.2%	0.5%
Public authorities & electric railroads	196	205	(4.4)%	(4.4)%	420	432	(2.8)%	(2.8)%
Total retail deliveries	8,749	8,771	(0.3)%	(0.8)%	17,953	18,032	(0.4)%	(0.9)%

Number of Electric Customers	As of June 30, 2017	As of June 30, 2016
Residential	1,461,931	1,449,450
Small commercial & industrial	150,783	149,523
Large commercial & industrial	3,105	3,088
Public authorities & electric railroads	9,795	9,813
Total	1,625,614	1,611,874

Electric Revenue	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	% Change	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	% Change
Retail Sales[a]						
Residential	$ 331	$ 355	(6.8)%	$ 713	$ 766	(6.9)%
Small commercial & industrial	100	106	(5.7)%	197	225	(12.4)%
Large commercial & industrial	57	65	(12.3)%	109	123	(11.4)%
Public authorities & electric railroads	8	9	(11.1)%	16	17	(5.9)%
Total retail	496	535	(7.3)%	1,035	1,131	(8.5)%
Other revenue[b]	54	52	3.8%	105	101	4.0%
Total electric revenue[c]	$ 550	$ 587	(6.3)%	$ 1,140	$ 1,232	(7.5)%

(a) Reflects delivery volumes and revenue from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.

(b) Other revenue primarily includes transmission revenue from PJM and wholesale electric revenue, in addition to rental income.

(c) Includes operating revenues from affiliates totaling $2 million for both the three months ended June 30, 2017 and 2016, and $3 million and $4 million for the six months ended June 30, 2017 and 2016, respectively.

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PECO Natural Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	% Change	Weather - Normal % Change	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	% Change	Weather - Normal % Change
Retail Delivery								
Retail sales[(a)]	7,621	7,883	(3.3)%	11.8%	34,832	34,994	(0.5)%	2.0%
Transportation and other	5,759	5,906	(2.5)%	(3.2)%	13,448	13,602	(1.1)%	(1.8)%
Total natural gas deliveries	13,380	13,789	(3.0)%	5.3%	48,280	48,596	(0.7)%	1.0%

Number of Natural Gas Customers	As of June 30, 2017	As of June 30, 2016
Residential	474,360	469,230
Commercial & industrial	43,404	43,046
Total retail	517,764	512,276
Transportation	768	811
Total	518,532	513,087

Natural Gas Revenue	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	% Change	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	% Change
Retail Sales						
Retail sales[(a)]	$ 72	$ 70	2.9%	$ 269	$ 256	5.1%
Transportation and other	8	7	14.3%	17	17	—%
Total natural gas revenues[(b)]	$ 80	$ 77	3.9%	$ 286	$ 273	4.8%

(a) Reflects delivery volumes and revenue 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. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.

(b) Includes operating revenues from affiliates totaling less than $1 million for both three months ended June 30, 2017 and 2016 and less than $1 million for both the six months ended June 30, 2017 and 2016.

Results of Operations — BGE

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	Favorable (Unfavorable) Variance
Operating revenues	$ 674	$ 680	$ (6)	$1,625	$1,609	$ 16
Purchased power and fuel expense	234	261	27	584	634	50
Revenues net of purchased power and fuel expense[(a)]	440	419	21	1,041	975	66
Other operating expenses						
Operating and maintenance	174	208	34	357	410	53
Depreciation and amortization	112	97	(15)	239	206	(33)
Taxes other than income	56	55	(1)	119	114	(5)
Total other operating expenses	342	360	18	715	730	15
Operating income	98	59	39	326	245	81
Other income and (deductions)						
Interest expense, net	(26)	(24)	(2)	(54)	(48)	(6)
Other, net	4	5	(1)	8	11	(3)
Total other income and (deductions)	(22)	(19)	(3)	(46)	(37)	(9)
Income before income taxes	76	40	36	280	208	72
Income taxes	31	6	(25)	111	73	(38)
Net income	45	34	11	169	135	34
Preference stock dividends	—	3	3	—	6	6
Net income attributable to common shareholder	$ 45	$ 31	$ 14	$ 169	$ 129	$ 40

(a) BGE evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenues net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenues net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Common Shareholder

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. BGE's Net income attributable to common shareholder for the three months ended June 30, 2017 was higher than the same period in 2016, primarily due to an increase in Revenues net of purchased power and fuel and lower Operating and maintenance expense. The increase in Revenues net of purchased power and fuel was primarily due to the impacts of the electric and natural gas distribution rate orders issued by the MDPSC in June 2016 and July 2016. The lower Operating and maintenance expense was primarily due to the absence of cost disallowances also resulting from the distribution rate orders issued by the MDPSC. These items were partially offset by higher income tax expense and an increase in Depreciation and amortization expense primarily related to the initiation of cost recovery of the AMI programs under the distribution rate orders and the impacts of increased capital investment.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. BGE's Net income attributable to common shareholder for the six months ended June 30, 2017 was higher than the same period in

2016, primarily due to an increase in Revenues net of purchased power and fuel and lower Operating and maintenance expense. The increase in Revenues net of purchased power and fuel was primarily due to the impacts of the electric and natural gas distribution rate orders issued by the MDPSC in June 2016 and July 2016. The lower Operating and maintenance expense was primarily due to decreased storm costs in 2017 and the absence of cost disallowances also resulting from the distribution rate orders issued by the MDPSC. These items were partially offset by higher income tax expense and an increase in Depreciation and amortization expense primarily related to the initiation of cost recovery of the AMI programs under the distribution rate orders and the impacts of increased capital investment.

Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to Operating revenues that are offset by their impact on Purchased power and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Operating revenues and Purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in the number of customers electing to use a competitive electric generation or natural gas supplier. All BGE customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The customers' choice of suppliers does not impact the volume of deliveries, but does affect revenue collected from customers related to supplied energy and natural gas service.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and six months ended June 30, 2017 and 2016 consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Electric	62%	62%	60%	59%
Natural Gas	68%	67%	53%	55%

The number of retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at June 30, 2017 and 2016 consisted of the following:

	June 30, 2017		June 30, 2016	
	Number of Customers	% of total retail customers	Number of customers	% of total retail customers
Electric	340,500	27%	337,400	27%
Natural Gas	150,400	22%	151,600	23%

The changes in BGE's Operating revenues net of purchased power and fuel expense for the three and six months ended June 30, 2017, compared to the same period in 2016, consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)			Six Months Ended June 30, 2017 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution rate increase	$ 9	$ 3	$ 12	$ 21	$29	$ 50
Regulatory required programs[(a)]	6	—	6	9	1	10
Transmission revenue	4	—	4	3	—	3
Other, net	(2)	1	(1)	1	2	3
Total increase	$ 17	$ 4	$ 21	$ 34	$32	$ 66

(a) Includes an increase of revenues for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An offsetting amount has been reflected in Operating and maintenance expense.

Distribution Rate Increase. The increase in distribution revenues for the three and six months ended June 30, 2017, compared to the same period in 2016, was primarily due to the impact of the electric and natural gas distribution rates charged to customers that became effective in June 2016 in accordance with the electric and natural gas distribution rate orders issued by the MDPSC in June 2016 and July 2016. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Revenue Decoupling. The demand for electricity and natural gas is affected by weather and usage conditions. The MDPSC allows BGE to record a monthly adjustment to its electric and natural gas distribution revenue from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service natural gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and natural gas distribution volumes, thereby recovering a specified dollar amount of distribution revenue per customer, by customer class, regardless of fluctuations in actual consumption levels. This allows BGE to recognize revenue at MDPSC-approved distribution charges per customer, regardless of what BGE's actual distribution volumes were for a billing period. Therefore, while this revenue is affected by customer growth (i.e., increase in the number of customers), it will not be affected by actual weather or usage conditions (i.e., changes in consumption per customer). BGE bills or credits customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

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 BGE's service territory. The changes in heating and cooling degree days in BGE's service territory for the three and six months ended June 30, 2017 compared to the same period in 2016 consisted of the following:

Heating and Cooling Degree-Days	2017	2016	Normal	% Change 2017 vs. 2016	% Change 2017 vs. Normal
Three Months Ended June 30,					
Heating Degree-Days	397	574	511	(30.8)%	(22.3)%
Cooling Degree-Days	283	219	255	29.2%	11.0%
Six Months Ended June 30,					
Heating Degree-Days	2,460	2,854	2,915	(13.8)%	(15.6)%
Cooling Degree-Days	283	219	255	29.2%	11.0%

Regulatory Required Programs. This represents the change in revenue collected under approved riders to recover costs incurred for the energy efficiency and demand response programs. The riders are designed to provide full 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 in BGE's Consolidated Statements of Operations and Comprehensive 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 other billing determinants. The transmission revenue stayed relatively consistent during the three and six months ended June 30, 2017 compared to the same period in 2016. See Operating and Maintenance Expense below and Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other, Net. Other net revenue, which can vary from period to period, includes commodity electric and gas revenue and other miscellaneous revenue such as service application and late payment fees; partially offset by commodity electric and gas purchased fuel and energy.

Operating and Maintenance Expense

The changes in Operating and maintenance expense for the three and six months ended June 30, 2017 compared to the same period in 2016, consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)	Six Months Ended June 30, 2017 Increase (Decrease)
Impairment on long-lived assets and losses on regulatory assets[(a)]	$ (51)	$ (51)
Storm-related costs	(2)	(14)
City of Baltimore conduit fees	(4)	(8)
BSC costs	—	3
Uncollectible accounts expense	7	—
Other[(b)]	16	17
Total decrease	$ (34)	$ (53)

(a) See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Includes an increase of costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An offsetting amount has been reflected in operating revenue.

Depreciation and Amortization

The changes in Depreciation and amortization expense for the three and six months ended June 30, 2017 compared to the same period in 2016 consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)	Six Months Ended June 30, 2017 Increase (Decrease)
Depreciation expense[(a)]	$ 1	$ 4
Regulatory asset amortization[(b)]	14	29
Total increase	$ 15	$ 33

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization increased for the three and six months ended June 30, 2017 compared to the same period in 2016 primarily due to an increase in regulatory asset amortization related to energy efficiency programs and the initiation of cost recovery of the AMI programs under the final electric and natural gas distribution rate case order issued by the MDPSC in June 2016 and increased depreciation from AMI program capital expenditures. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Taxes Other Than Income

Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income for the three and six months ended June 30, 2017 compared to the same period in 2016 remained relatively consistent.

Interest Expense, Net

Interest expense, net increased during the three and six months ended June 30, 2017, compared to the same period in 2016 primarily due to the issuance of Notes in August 2016.

Effective Income Tax Rate

BGE's effective income tax rate was 40.8% and 15.0% for the three months ended June 30, 2017 and 2016, respectively. BGE's effective income tax rate was 39.6% and 35.1% for the six months ended June 30, 2017 and 2016, respectively. See Note 11 — 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 Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	% Change	Weather - Normal % Change	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	% Change	Weather - Normal % Change
Retail Deliveries[a]								
Residential	2,629	2,616	0.5%	(4.5)%	5,756	6,095	(5.6)%	(5.2)%
Small commercial & industrial	677	692	(2.2)%	(5.2)%	1,425	1,466	(2.8)%	(4.5)%
Large commercial & industrial	3,373	3,417	(1.3)%	(0.9)%	6,641	6,635	0.1%	(1.7)%
Public authorities & electric railroads	72	72	—%	(0.1)%	140	143	(2.1)%	(2.4)%
Total electric deliveries	6,751	6,797	(0.7)%	(2.8)%	13,962	14,339	(2.6)%	(3.5)%

Number of Electric Customers	As of June 30, 2017	As of June 30, 2016
Residential	1,154,330	1,142,073
Small commercial & industrial	113,329	112,980
Large commercial & industrial	12,113	11,980
Public authorities & electric railroads	276	281
Total	1,280,048	1,267,314

Electric Revenue	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	% Change	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	% Change
Retail Sales[a]						
Residential	$ 315	$ 324	(2.8)%	$ 720	$ 753	(4.4)%
Small commercial & industrial	63	65	(3.1)%	135	137	(1.5)%
Large commercial & industrial	110	115	(4.3)%	223	215	3.7%
Public authorities & electric railroads	8	9	(11.1)%	15	18	(16.7)%
Total retail	496	513	(3.3)%	1,093	1,123	(2.7)%
Other revenue[b][c]	75	71	5.6%	144	141	2.1%
Total electric revenue	$ 571	$ 584	(2.2)%	$ 1,237	$ 1,264	(2.1)%

(a) Reflects delivery volumes and revenue from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.
(b) Other revenue primarily includes wholesale transmission revenue and late payment charges.
(c) Includes operating revenues from affiliates totaling $2 million and $2 million for the three months ended June 30, 2017 and 2016, respectively, and $3 million and $4 million for the six months ended June 30, 2017 and 2016, respectively.

BGE Natural Gas Operating Statistics and Revenue Detail

	Three Months Ended June 30,				Six Months Ended June 30,			
Deliveries to Customers (in mmcf)	2017	2016	% Change	Weather - Normal % Change	2017	2016	% Change	Weather - Normal % Change
Retail Deliveries[a]								
Retail sales	13,028	17,672	(26.3)%	(16.3)%	49,399	56,256	(12.2)%	(3.2)%
Transportation and other[b]	116	271	(57.2)%	n/a	2,395	2,767	(13.4)%	n/a
Total natural gas deliveries	13,144	17,943	(26.7)%	(16.3)%	51,794	59,023	(12.2)%	(3.2)%

	As of June 30,	
Number of Gas Customers	2017	2016
Residential	624,392	618,268
Commercial & industrial	44,020	44,078
Total	668,412	662,346

	Three Months Ended June 30,			Six Months Ended June 30,		
Natural Gas Revenue	2017	2016	% Change	2017	2016	% Change
Retail Sales[a]						
Retail sales	$ 99	$ 93	6.5%	$ 369	$ 331	11.5%
Transportation and other[b]	4	3	33.3%	19	14	35.7%
Total natural gas revenues[c]	$ 103	$ 96	7.3%	$ 388	$ 345	12.5%

(a) Reflects delivery volumes and revenue from customers purchasing natural gas directly from BGE and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. The cost of natural gas is charged to customers purchasing natural gas from BGE.
(b) Transportation and other gas revenue includes off-system revenue of 116 mmcfs ($1 million) and 271 mmcfs ($2 million) for the three months ended June 30, 2017 and 2016, respectively. Transportation and other gas revenue includes off-system revenue of 2,395 mmcfs ($13 million) and 2,767 mmcfs ($11 million) for the six months ended June 30, 2017 and 2016, respectively.
(c) Includes operating revenues from affiliates totaling $1 million and $2 million for the three months ended June 30, 2017 and 2016, respectively, and $5 million and $5 million for the six months ended June 30, 2017 and 2016, respectively.

Results of Operations — PHI

PHI’s results of operations include the results of its three reportable segments, Pepco, DPL and ACE for all periods presented below. For “Predecessor” reporting periods, PHI’s results of operations also include the results of PES and PCI. See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding PHI’s reportable segments. All material intercompany accounts and transactions have been eliminated in consolidation. A separate specific discussion of the results of operations for Pepco, DPL and ACE is presented elsewhere in this report.

As a result of the PHI Merger, the following consolidated financial results present two separate reporting periods for 2016. The "Predecessor" reporting period represents PHI's results of operations for the period from January 1, 2016 to March 23, 2016. The "Successor" reporting periods represent PHI's results of operations for the three and six months ended June 30, 2017, the three months ended June 30, 2016 and for the period from March 24, 2016 to June 30, 2016. All amounts presented below are before the impact of income taxes, except as noted.

	Successor Three Months Ended June 30, 2017	Successor Three Months Ended June 30, 2016	Favorable (Unfavorable) Variance	Successor Six Months Ended June 30, 2017	Successor March 24 to June 30, 2016	Predecessor January 1 to March 23, 2016
Operating revenues	$1,074	$1,066	$ 8	$ 2,248	$ 1,171	$ 1,153
Purchased power and fuel expense	383	416	33	845	454	497
Revenue net of purchased power and fuel expense[(a)]	691	650	41	1,403	717	656
Other operating expenses						
Operating and maintenance	269	246	(23)	524	695	294
Depreciation and amortization	165	160	(5)	332	174	152
Taxes other than income	110	108	(2)	221	123	105
Total other operating expenses	544	514	(30)	1,077	992	551
Gain on sales of assets	1	—	1	1	—	—
Operating income (loss)	148	136	12	327	(275)	105
Other income and (deductions)						
Interest expense, net	(59)	(66)	7	(122)	(71)	(65)
Other, net	13	11	2	26	12	(4)
Total other income and (deductions)	(46)	(55)	9	(96)	(59)	(69)
Income (loss) before income taxes	102	81	21	231	(334)	36
Income taxes	36	29	(7)	26	(77)	17
Net income (loss)	$ 66	$ 52	$ 14	$ 205	$ (257)	$ 19

(a) PHI evaluates its operating performance using the measure of revenue net of purchased power and fuel expense for electric and natural gas sales. PHI believes revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. PHI has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power and fuel expense 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.

Successor Period Three Months Ended June 30, 2017 Compared to Successor Period Three Months Ended June 30, 2016

Net Income

PHI's Net income for the Successor period of three months ended June 30, 2017 was $66 million compared to $52 million for the Successor period of three months ended June 30, 2016. The increase in Net income reflects the impact of increases in electric distribution and natural gas rates within Revenue net of purchased power expense (Pepco electric distribution rates effective November 2016 in Maryland, DPL electric distribution rates effective February 2017 in Maryland, DPL electric distribution and natural gas rates effective July 2016 and December 2016 in Delaware, and ACE electric distribution rates effective August 2016 in New Jersey). Operating and maintenance expense increased primarily due to higher preventative maintenance expense, partially offset by merger commitment adjustments recorded in June 2017.

Operating Revenue Net of Purchased Power and Fuel Expense

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed above, increased by $41 million for the three months ended June 30, 2017 as compared to the three months ended June 30, 2016. The increase is primarily attributable to the following favorable factors:

- Increase of $14 million at Pepco primarily related to the impact of the new electric distribution rates charged to customers in Maryland that became effective in November 2016;
- Increase of $10 million at DPL primarily related to the impact of the new electric distribution and natural gas rates charged to Delaware customers that became effective in July 2016 and December 2016 and the impact of new electric distribution rates charged to Maryland customers that became effective in February 2017; and
- Increase of $13 million at ACE primarily related to the impact of the new electric distribution base rate charged to customers that became effective in August 2016.

Operating and Maintenance Expense

Operating and maintenance expense increased by $23 million for the three months ended June 30, 2017 as compared to the three months ended June 30, 2016. The increase is attributable to the following unfavorable factors:

- Increase of $11 million at Pepco primarily due to an increase in preventative maintenance costs and higher uncollectible expense, partially offset by a merger commitment adjustment;
- Increase of $10 million at ACE primarily due to an increase in preventive maintenance costs;
- Increase of $6 million at Corporate primarily due to an increase in BSC costs and service company allocations;
- Partially offset by a decrease of $4 million at DPL due primarily to lower write-offs of construction work in progress and a merger commitment adjustment, partially offset by higher preventative maintenance costs.

Depreciation and Amortization Expense

Depreciation and amortization expense increased by $5 million primarily due to higher depreciation as a result of higher Maryland depreciation rates at Pepco effective November 2016 and at DPL effective February 2017 and due to ongoing capital expenditures at Pepco, DPL, and ACE, partially offset by lower amortization expense at ACE resulting from lower revenue due to rate decreases effective October 2016 for the ACE Transition Bond Charge and ACE Market Transition Charge Tax.

Taxes Other Than Income

Taxes other than income increased by $2 million primarily due to higher property taxes at Pepco.

Interest Expense, Net

Interest expense decreased by $7 million primarily due to the redemption of long-term debt in December 2016 and lower short-term debt interest rates.

Other, Net

Other, net for the three months ended June 30, 2017 remained relatively level compared to the same period in 2016.

Effective Income Tax Rate

PHI's effective income tax rate was 35.3% and 35.8% for the three months ended June 30, 2017 and 2016, respectively. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Successor Period Six Months Ended June 30, 2017

PHI's Net income for the Successor period of six months ended June 30, 2017 was $205 million. There were no significant changes in the underlying trends affecting PHI's operations during the Successor period of six months ended June 30, 2017 except for the impact of increases in electric distribution and natural gas rates within Revenue net of purchased power expense (Pepco electric distribution rates effective November 2016 in Maryland, DPL electric distribution rates effective February 2017 in Maryland, DPL electric distribution and natural gas rates effective July 2016 and December 2016 in Delaware, and ACE electric distribution rates effective August 2016 in New Jersey). Lower uncollectible accounts expense and the deferral of merger-related costs to a regulatory asset contributed to lower Operating and maintenance expense. Income taxes were lower due to unrecognized tax benefits of $59 million for uncertain tax positions related to the deductibility of certain merger commitments in the first quarter of 2017.

PHI's effective income tax rate for the Successor period of six months ended June 30, 2017 was 11.3%. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Successor Period March 24, 2016 to June 30, 2016

PHI's Net loss for the Successor period from March 24, 2016 to June 30, 2016 was $257 million. There were no significant changes in the underlying trends affecting PHI's results of operations during the Successor period of March 24, 2016 to June 30, 2016 except for the pre-tax recording of $419 million of non-recurring merger-related costs within Operating and maintenance expense.

PHI's effective income tax rate for the Successor period of March 24, 2016 to June 30, 2016 was 23.1%. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Predecessor Period January 1, 2016 to March 23, 2016

PHI's Net income for the Predecessor period of January 1, 2016 to March 23, 2016 was $19 million. There were no significant changes in the underlying trends affecting PHI's results of operations during the Predecessor period of January 1, 2016 to March 23, 2016 except for the pre-tax recording of $29 million of non-recurring merger-related costs within Operating and maintenance expense and $18 million of preferred stock derivative expense within Other, net.

PHI's effective income tax rate for the Predecessor period of January 1, 2016 to March 23, 2016 was 47.2%. See Note 11 — 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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Results of Operations—Pepco

	Three Months Ended June 30,		Favorable (Unfavorable) Variance	Six Months Ended June 30,		Favorable (Unfavorable) Variance
	2017	2016		2017	2016	
Operating revenues	$ 514	$ 509	$ 5	$1,045	$1,061	$ (16)
Purchased power expense	143	152	9	309	351	42
Revenue net of purchased power expense[(a)]	371	357	14	736	710	26
Other operating expenses						
Operating and maintenance	120	109	(11)	234	399	165
Depreciation and amortization	78	70	(8)	160	144	(16)
Taxes other than income	90	89	(1)	180	182	2
Total other operating expenses	288	268	(20)	574	725	151
Gain on sales of assets	1	8	(7)	1	8	(7)
Operating income (loss)	84	97	(13)	163	(7)	170
Other income and (deductions)						
Interest expense, net	(28)	(31)	3	(58)	(68)	10
Other, net	7	6	1	15	14	1
Total other income and (deductions)	(21)	(25)	4	(43)	(54)	11
Income (loss) before income taxes	63	72	(9)	120	(61)	181
Income taxes	20	23	3	19	(1)	(20)
Net income (loss)	$ 43	$ 49	$ (6)	$ 101	$ (60)	$ 161

(a) Pepco evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. Pepco believes revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Pepco has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense 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.

Net Income (Loss)

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. Pepco's Net income for the three months ended June 30, 2017, was lower than the same period in 2016, primarily due to higher Operating and maintenance expense due to an increase in preventative maintenance costs and higher uncollectible expense, higher depreciation expense due to increased depreciation rates in Maryland effective November 2016 and a gain on sale of land recorded in 2016, partially offset by an increase in Revenue net of purchased power expense resulting from higher electric distribution revenues as a result of the distribution rate increase approved by the MDPSC effective November 2016.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. Pepco's Net income (loss) for the six months ended June 30, 2017, was higher than the same period in 2016, primarily due to an increase in Revenue net of purchased power expense resulting from higher electric distribution revenues as a result of the distribution rate increase approved by the MDPSC effective November 2016, lower Operating and maintenance expense due to merger-related costs recognized in March 2016 and lower uncollectible accounts expense, and a decrease in income tax reserves in the first quarter of 2017 for uncertain tax positions related to the deductibility of certain merger commitments, partially offset by higher depreciation expense due to increased depreciation rates in Maryland effective November 2016.

Operating Revenue Net of Purchased Power Expense

Operating revenues include revenue from the distribution and supply of electricity to Pepco's customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that Pepco receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All Pepco customers have the choice to purchase electricity from competitive electric generation suppliers. The customers' choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three and six months ended June 30, 2017, compared to the same periods in 2016, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Electric	67%	67%	66%	65%

Retail customers purchasing electric generation from competitive electric generation suppliers at June 30, 2017 and 2016 consisted of the following:

	June 30, 2017		June 30, 2016	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	179,736	21%	175,657	21%

Retail deliveries purchased from competitive electric generation suppliers represented 74% and 74% of Pepco's retail kWh sales to the District of Columbia customers and 61% and 60% of Pepco's retail kWh sales to Maryland customers for the three and six months ended June 30, 2017, respectively and 73% and 73% of Pepco's retail kWh sales to the District of Columbia customers and 61% and 59% of Pepco's retail kWh sales to Maryland customers for the three and six months ended June 30, 2016, respectively.

Operating revenues include transmission enhancement credits that Pepco receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Purchased power expense consists of the cost of electricity purchased by Pepco to fulfill its default electricity supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders.

The changes in Pepco's operating revenues net of purchased power expense for the three and six months ended June 30, 2017 compared to the same periods in 2016 consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)	Six Months Ended June 30, 2017 Increase (Decrease)
Volume	$ 4	$ 9
Pricing — distribution revenues	11	27
Regulatory required programs	(3)	(13)
Transmission revenues	4	6
Other	(2)	(3)
Total increase	$ 14	$ 26

Revenue Decoupling. Pepco's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of Pepco in Maryland and in the District of Columbia, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland and the District of Columbia to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

In accounting for the BSA in Maryland and the District of Columbia, a Revenue Decoupling Adjustment is recorded representing either (i) a positive adjustment equal to the amount by which revenue from Maryland and the District of Columbia retail distribution sales falls short of the revenue that Pepco is entitled to earn based on the approved distribution charge per customer or (ii) a negative adjustment equal to the amount by which revenue from such distribution sales exceeds the revenue that Pepco is entitled to earn based on the approved distribution charge per customer.

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 Pepco's service territory. The changes in heating and cooling degree days in Pepco's service territory for the three and six months ended June 30, 2017 compared to the same periods in 2016 and normal weather consisted of the following:

				% Change	
	2017	2016	Normal	2017 vs. 2016	2017 vs. Normal
Three Months Ended June 30,					
Heating Degree-Days	314	397	500	(20.9)%	(37.2)%
Cooling Degree-Days	546	452	475	20.8%	14.9%
Six Months Ended June 30,					
Heating Degree-Days	2,062	2,407	2,638	(14.3)%	(21.8)%
Cooling Degree-Days	550	454	478	21.1%	15.1%

Volume. The increase in operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three and six months ended June 30, 2017 compared to the same periods in 2016, primarily reflects the impact of customer growth.

Pricing — Distribution Revenues. The increase in electric operating revenues net of purchased power expense as a result of pricing for the three and six months ended June 30, 2017 compared to the same periods in

2016 was primarily due to the impact of higher electric distribution rates charged to customers in Maryland that became effective in November 2016. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. 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 other taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

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 other billing adjustments. The increase in revenue net of purchased power expense for the three months ended June 30, 2017 compared to the same period in 2016 is a result of higher rates effective June 1, 2017 and June 1, 2016 related to increases in transmission plant investment and operating expenses. The increase in revenue net of purchased power expense for the six months ended June 30, 2017 compared to the same period in 2016 is a result of higher rates effective June 1, 2017 and June 1, 2016 related to increases in transmission plant investment and operating expenses, partially offset by lower revenue related to the MAPP abandonment recovery period that ended in March 2016.

Operating and Maintenance Expense

	Three Months Ended June 30,		Increase (Decrease)	Six Months Ended June 30,		Increase (Decrease)
	2017	2016		2017	2016	
Operating and maintenance expense — baseline	$ 117	$ 107	$ 10	$ 232	$ 394	$ (162)
Operating and maintenance expense —regulatory required programs[(a)]	3	2	1	2	5	(3)
Total operating and maintenance expense	$ 120	$ 109	$ 11	$ 234	$ 399	$ (165)

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that 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.

The changes in Operating and maintenance expense for the three and six months ended June 30, 2017 compared to the same periods in 2016, consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)	Six Months Ended June 30, 2017 Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ 7	$ 12
Storm-related costs	—	1
Remeasurement of AMI-related regulatory asset[(a)]	(7)	(7)
Uncollectible accounts expense	5	(4)
Deferral of merger-related costs to regulatory asset	8	7
BSC and PHISCO allocations[(b)]	4	(23)
Merger commitments[(c)]	(6)	(145)
Other	(1)	(3)
	10	(162)
Regulatory required programs		
Purchased power administrative costs	1	(3)
Total increase (decrease)	$ 11	$ (165)

(a) Related to a remeasurement of a regulatory asset for legacy meters recognized in 2016.
(b) Primarily related to merger severance and compensation costs recognized in 2016.
(c) Primarily related to merger-related commitments for customer rate credits and charitable contributions recognized in 2016.

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for the three and six months ended June 30, 2017 compared to the same periods in 2016, consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)	Six Months Ended June 30, 2017 Increase (Decrease)
Depreciation expense[(a)]	$ 8	$ 17
Regulatory asset amortization	—	(1)
Total increase	$ 8	$ 16

(a) Depreciation expense increased due to higher depreciation rates in Maryland effective November 2016 and due to ongoing capital expenditures.

Taxes Other Than Income

Taxes other than income for the three and six months ended June 30, 2017 compared to the same periods in 2016, remained relatively constant.

Gain on sales of assets

Gain on sales of assets for the three and six months ended June 30, 2017 compared to the same periods in 2016 decreased due to a second quarter 2016 gain recorded from the sale of land.

Interest Expense, Net

Interest expense, net for the three months ended June 30, 2017 compared to the same period in 2016, remained relatively constant.

Interest expense, net for the six months ended June 30, 2017 compared to the same period in 2016 decreased primarily due to the recording of interest expense for an uncertain tax position in the first quarter of 2016 and an increase in capitalized AFUDC interest.

Other, Net

Other, net for the three and six months ended June 30, 2017 compared to the same periods in 2016 remained relatively constant.

Effective Income Tax Rate

Pepco’s effective income tax rate was 31.7% and 31.9% for the three months ended June 30, 2017 and 2016, respectively. Pepco’s effective income tax rate was 15.8% and 1.6% for the six months ended June 30, 2017 and 2016, respectively. In the first quarter of 2017, Pepco decreased its liability for unrecognized tax benefits by $21 million resulting in a benefit to Income taxes and a corresponding decrease in its effective tax rate. See Note 11 — 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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Pepco Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2017	2016	% Change	Weather-Normal % Change	Six Months Ended June 30, 2017	2016	% Change	Weather-Normal % Change
Retail Deliveries[a]								
Residential	1,757	1,760	(0.2)%	3.0%	3,757	3,978	(5.6)%	(1.2)%
Small commercial & industrial	326	348	(6.3)%	(5.2)%	652	730	(10.7)%	(9.0)%
Large commercial & industrial	3,675	3,631	1.2%	1.3%	7,160	7,576	(5.5)%	(5.0)%
Public authorities & electric railroads	172	176	(2.3)%	(2.3)%	362	364	(0.5)%	(0.8)%
Total retail deliveries	5,930	5,915	0.3%	1.3%	11,931	12,648	(5.7)%	(3.9)%

Number of Electric Customers	As of June 30, 2017	2016
Residential	787,708	771,541
Small commercial & industrial	53,393	53,345
Large commercial & industrial	21,767	21,401
Public authorities & electric railroads	139	127
Total	863,007	846,414

Electric Revenue	Three Months Ended June 30, 2017	2016	% Change	Six Months Ended June 30, 2017	2016	% Change
Retail Sales[a]						
Residential	$ 220	$ 220	—%	$ 461	$ 476	(3.2)%
Small commercial & industrial	41	36	13.9%	75	73	2.7%
Large commercial & industrial	192	195	(1.5)%	387	395	(2.0)%
Public authorities & electric railroads	8	8	—%	16	16	—%
Total retail	461	459	0.4%	939	960	(2.2)%
Other revenue[b]	53	50	6.0%	106	101	5.0%
Total electric revenue[c]	$ 514	$ 509	1.0%	$ 1,045	$ 1,061	(1.5)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from Pepco and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from Pepco, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.
(c) Includes operating revenues from affiliates totaling $1 million and $1 million for the three months ended June 30, 2017 and 2016, respectively, and $3 million and $3 million for the six months ended June 30, 2017 and 2016, respectively.

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Results of Operations — DPL

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	Favorable (Unfavorable) Variance
Operating revenues	$282	$281	$ 1	$644	$643	$ 1
Purchased power and fuel expense	113	122	9	270	298	28
Revenues net of purchased power and fuel expense[(a)]	169	159	10	374	345	29
Other operating expenses						
Operating and maintenance	74	78	4	148	283	135
Depreciation and amortization	40	38	(2)	79	76	(3)
Taxes other than income	14	13	(1)	28	28	—
Total other operating expenses	128	129	1	255	387	132
Operating income (loss)	41	30	11	119	(42)	161
Other income and (deductions)						
Interest expense, net	(13)	(13)	—	(25)	(25)	—
Other, net	3	3	—	6	6	—
Total other income and (deductions)	(10)	(10)	—	(19)	(19)	—
Income (loss) before income taxes	31	20	11	100	(61)	161
Income taxes	12	8	(4)	24	(1)	(25)
Net income (loss)	$ 19	$ 12	$ 7	$ 76	$ (60)	$ 136

(a) DPL evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales and revenue net of fuel expense for natural gas sales. DPL believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements because they provide information that can be used to evaluate its operational performance. DPL has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense and Revenue net of fuel expense 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.

Net Income (Loss)

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. DPL's Net income for the three months ended June 30, 2017, was higher than the same period in 2016 as a result of an increase in Revenue net of purchased power and fuel expense primarily resulting from higher electric distribution and natural gas revenues as a result of the distribution rate increases approved by the DPSC effective July 2016 and December 2016 and by the MDPSC effective February 2017.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. DPL's Net income (loss) for the six months ended June 30, 2017, was higher than the same period in 2016 as a result of an increase in Revenue net of purchased power and fuel expense primarily resulting from higher electric distribution and natural gas revenues as a result of the distribution rate increases approved by the DPSC effective July 2016 and December 2016 and by the MDPSC effective February 2017, lower Operating and maintenance expense due to merger-related costs recognized in March 2016, lower uncollectible accounts expense, and the deferral of merger-related costs to a regulatory asset in 2017, and a decrease in income tax reserves in the first quarter of 2017 for uncertain tax positions related to the deductibility of certain merger commitments.

Revenues Net of Purchased Power and Fuel Expense

Operating revenues include revenue from the distribution and supply of electricity to DPL's customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that DPL receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

Electric and natural gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All DPL customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The customers' choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and six months ended June 30, 2017 and 2016, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Electric	55%	56%	52%	52%
Natural Gas	44%	39%	31%	29%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at June 30, 2017 and 2016 consisted of the following:

	June 30, 2017		June 30, 2016	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	79,620	15.3%	76,709	14.9%
Natural Gas	155	0.1%	157	0.1%

Retail deliveries purchased from competitive electric generation suppliers represented 57% and 55% of DPL's retail kWh sales to Delaware customers and 51% and 48% of DPL's retail kWh sales to Maryland customers for the three and six months ended June 30, 2017, respectively and 57% and 54% of DPL's retail kWh sales to Delaware customers and 52% and 48% of DPL's retail kWh sales to Maryland customers for the three and six months ended June 30, 2016, respectively.

Operating revenues include transmission enhancement credits that DPL receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Natural gas operating revenue includes sources that are subject to price regulation (Regulated Gas Revenue) and those that generally are not subject to price regulation (Other Gas Revenue). Regulated gas revenue includes the revenue DPL receives from on-system natural gas delivered sales and the transportation of natural gas for customers within its service territory at regulated rates. Other gas revenue consists of off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers. Off-system sales are made possible when low demand for natural gas by regulated customers creates excess pipeline capacity.

Purchased power expense consists of the cost of electricity purchased by DPL to fulfill its default electricity supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders. Purchased fuel expense consists of the cost of gas purchased by DPL to fulfill its obligation to regulated gas customers and, as such, is recoverable from customers in accordance with the terms of public service commission orders. It also includes the cost of gas purchased for off-system sales.

The changes in DPL's operating revenues net of purchased power and fuel expense for the three and six months ended June 30, 2017 compared to the same periods in 2016 consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)			Six Months Ended June 30, 2017 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$ (1)	$ (8)	$ (9)	$ (3)	$(12)	$(15)
Volume	2	5	7	1	9	10
Pricing — distribution revenues	12	(1)	11	31	2	33
Regulatory required programs	1	—	1	2	—	2
Transmission revenues	1	—	1	(1)	—	(1)
Other	—	(1)	(1)	1	(1)	—
Total increase (decrease)	$ 15	$ (5)	$ 10	$ 31	$ (2)	$ 29

Revenue Decoupling. DPL's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of DPL in Maryland, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. A modified fixed variable rate design, which would provide for a charge not tied to a customer's volumetric consumption of electricity or natural gas, has been proposed for DPL electricity and natural gas customers in Delaware. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

In accounting for the BSA in Maryland, a Revenue Decoupling Adjustment is recorded representing either (i) a positive adjustment equal to the amount by which revenue from Maryland retail distribution sales falls short of the revenue that DPL is entitled to earn based on the approved distribution charge per customer or (ii) a negative adjustment equal to the amount by which revenue from such distribution sales exceeds the revenue that DPL is entitled to earn based on the approved distribution charge per customer.

Weather. The demand for electricity and natural gas in areas not subject to the BSA 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 and six months ended June 30, 2017 compared to the same periods in 2016, operating revenue net of purchased power and fuel expense was lower due to the impact of unfavorable weather conditions in DPL's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in DPL's electric service territory and a 30-year period in DPL's natural gas service territory. The changes in heating and cooling degree days in DPL's service territory for the three and six months ended June 30, 2017 compared to the same periods in 2016 and normal weather consisted of the following:

Electric Service Territory Three Months Ended June 30,	2017	2016	Normal	% Change 2017 vs. 2016	% Change 2017 vs. Normal
Heating Degree-Days	481	551	702	(12.7)%	(31.5)%
Cooling Degree-Days	342	304	264	12.5%	29.5%
Six Months Ended June 30,					
Heating Degree-Days	2,483	2,798	3,119	(11.3)%	(20.4)%
Cooling Degree-Days	342	307	266	11.4%	28.6%

Natural Gas Service Territory Three Months Ended June 30,	2017	2016	Normal	% Change 2017 vs. 2016	% Change 2017 vs. Normal
Heating Degree-Days	372	559	504	(33.5)%	(26.2)%
Six Months Ended June 30,					
Heating Degree-Days	2,403	2,893	3,020	(16.9)%	(20.4)%

Volume. The increase in operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three and six months ended June 30, 2017 compared to the same periods in 2016, primarily reflects the impact of increased natural gas average customer usage and customer growth.

Pricing — Distribution Revenues. The increase in electric operating revenues net of purchased power expense as a result of pricing for the three and six months ended June 30, 2017 compared to the same periods in 2016 was primarily due to the impact of higher electric distribution and natural gas rates charged to Delaware customers that became effective in July and December 2016 and the impact of higher electric distribution rates charged to Maryland customers that became effective in February 2017. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. 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. Refer to the operating and maintenance expense discussion below for additional information on included programs.

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 other billing adjustments. The increase in revenue net of purchased power expense for the three months ended June 30, 2017 compared to the same period in 2016 is a result of higher rates effective June 1, 2017 and June 1, 2016 related to increases in transmission plant investment and operating expenses. The decrease in revenue net of purchased power expense for the six months ended June 30, 2017 compared to the same period in 2016 is a result of lower revenue related to the MAPP abandonment recovery period that ended in March 2016, partially offset by higher rates effective June 1, 2017 and June 1, 2016 related to increases in transmission plant investment and operating expenses.

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Operating and Maintenance Expense

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Increase (Decrease)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	Increase (Decrease)
Operating and maintenance expense — baseline	$ 72	$ 76	$ (4)	$ 145	$ 278	$ (133)
Operating and maintenance expense —regulatory required programs[(a)]	2	2	—	3	5	(2)
Total operating and maintenance expense	$ 74	$ 78	$ (4)	$ 148	$ 283	$ (135)

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that 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.

The changes in Operating and maintenance expense for the three and six months ended June 30, 2017 compared to the same periods in 2016, consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)	Six Months Ended June 30, 2017 Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ 4	$ —
Storm-related costs	(1)	6
Uncollectible accounts expense	(2)	(7)
Remeasurement of AMI-related regulatory asset[(a)]	(1)	(1)
Deferral of merger-related costs to regulatory asset	2	(7)
Write-off of construction work in progress	(3)	—
BSC and PHISCO allocations[(b)]	1	(15)
Merger commitments[(c)]	(1)	(104)
Other	(3)	(5)
	(4)	(133)
Regulatory required programs		
Purchased power administrative costs	—	(2)
Total decrease	$ (4)	$ (135)

(a) Related to a remeasurement of a regulatory asset for legacy meters recognized in 2016.
(b) Primarily related to merger severance and compensation costs recognized in 2016.
(c) Primarily related to merger-related commitments for customer rate credits and charitable contributions recognized in 2016.

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for the three and six months ended June 30, 2017 compared to the same periods in 2016 consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)	Six Months Ended June 30, 2017 Increase (Decrease)
Depreciation expense[(a)]	$ 3	$ 6
Regulatory asset amortization[(b)]	(1)	(3)
Total increase	$ 2	$ 3

(a) Depreciation expense increased due to higher depreciation rates in Maryland effective February 2017 and due to ongoing capital expenditures.
(b) Regulatory asset amortization decreased for the six months ended June 30, 2017 compared to the same period in 2016 due to lower amortization of MAPP abandonment costs.

Taxes Other Than Income

Taxes other than income for the three and six months ended June 30, 2017 compared to the same periods in 2016 remained relatively constant.

Interest Expense, Net

Interest expense, net for the three and six months ended June 30, 2017 compared to the same periods in 2016 remained relatively constant.

Other, Net

Other, net for the three and six months ended June 30, 2017 compared to the same periods in 2016 remained relatively constant.

Effective Income Tax Rate

DPL's effective income tax rate was 38.7% and 40.0% for the three months ended June 30, 2017 and 2016, respectively. DPL's effective income tax rate was 24.0% and 1.6% for the six months ended June 30, 2017 and 2016, respectively. In the first quarter of 2017, DPL decreased its liability for unrecognized tax benefits by $16 million resulting in a benefit to Income taxes and a corresponding decrease in its effective tax rate. See Note 11 — 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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DPL Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	% Change	Weather-Normal % Change	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	% Change	Weather-Normal % Change
Retail Deliveries[a]								
Residential	1,045	1,038	0.7%	5.1%	2,404	2,465	(2.5)%	1.9%
Small commercial & industrial	526	532	(1.1)%	(0.2)%	1,057	1,104	(4.3)%	(3.2)%
Large commercial & industrial	1,131	1,164	(2.8)%	(2.8)%	2,195	2,242	(2.1)%	(1.8)%
Public authorities & electric railroads	12	12	—%	—%	25	26	(3.8)%	(3.8)%
Total retail deliveries	2,714	2,746	(1.2)%	0.7%	5,681	5,837	(2.7)%	(0.5)%

Number of Electric Customers	As of June 30, 2017	As of June 30, 2016
Residential	458,361	454,402
Small commercial & industrial	60,499	59,904
Large commercial & industrial	1,410	1,417
Public authorities & electric railroads	636	643
Total	520,906	516,366

Electric Revenue	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	% Change	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	% Change
Retail Sales[a]						
Residential	$ 144	$ 143	0.7%	$ 325	$ 323	0.6%
Small commercial & industrial	45	46	(2.2)%	89	95	(6.3)%
Large commercial & industrial	25	25	—%	51	50	2.0%
Public authorities & electric railroads	4	3	33.3%	8	7	14.3%
Total retail	218	217	0.5%	473	475	(0.4)%
Other revenue[b]	42	38	10.5%	84	83	1.2%
Total electric revenue[c]	$ 260	$ 255	2.0%	$ 557	$ 558	(0.2)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from DPL and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from DPL, revenue also reflects the cost of energy and transmission.

(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.

(c) Includes operating revenues from affiliates totaling $2 million and $2 million for the three months ended June 30, 2017 and 2016, respectively, and $4 million and $4 million for the six months ended June 30, 2017 and 2016, respectively.

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DPL Natural Gas Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in mmcf)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	% Change	Weather-Normal % Change	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	% Change	Weather-Normal % Change
Retail Deliveries								
Retail sales	1,678	2,072	(19.0)%	4.3%	7,610	8,132	(6.4)%	8.3%
Transportation & other	1,325	1,321	0.3%	4.0%	3,493	3,289	6.2%	9.9%
Total natural gas deliveries	3,003	3,393	(11.5)%	4.2%	11,103	11,421	(2.8)%	8.8%

Number of Gas Customers	As of June 30, 2017	As of June 30, 2016
Residential	121,166	119,592
Commercial & industrial	9,743	9,669
Transportation & other	155	157
Total	131,064	129,418

Natural Gas Revenue	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	% Change	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	% Change
Retail Sales[(a)]						
Retail sales	$ 17	$ 21	(19.0)%	$ 75	$ 74	1.4%
Transportation & other[(b)]	5	5	—%	12	11	9.1%
Total natural gas revenues	$ 22	$ 26	(15.4)%	$ 87	$ 85	2.4%

(a) Reflects delivery volumes and revenues 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. For customers purchasing natural gas from DPL, revenue also reflects the cost of natural gas.

(b) Transportation and other revenue includes off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers.

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Results of Operations — ACE

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	Favorable (Unfavorable) Variance
Operating revenues	$ 270	$ 270	$ —	$ 544	$ 561	$ (17)
Purchased power expense	128	141	13	266	298	32
Revenues net of purchased power expense[(a)]	142	129	13	278	263	15
Other operating expenses						
Operating and maintenance	78	68	(10)	152	280	128
Depreciation and amortization	37	41	4	72	81	9
Taxes other than income	2	2	—	4	4	—
Total other operating expenses	117	111	(6)	228	365	137
Gain on sale of assets	—	1	(1)	—	1	(1)
Operating income (loss)	25	19	6	50	(101)	151
Other income and (deductions)						
Interest expense, net	(15)	(16)	1	(30)	(32)	2
Other, net	2	2	—	4	5	(1)
Total other income and (deductions)	(13)	(14)	1	(26)	(27)	1
Income (loss) before income taxes	12	5	7	24	(128)	152
Income taxes	4	2	(2)	(12)	(31)	(19)
Net income (loss)	$ 8	$ 3	$ 5	$ 36	$ (97)	$ 133

(a) ACE evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. ACE believes Revenue net of purchased power expense is a useful measurement of its performance because it provides information that can be used to evaluate its operational performance. ACE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense 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.

Net Income (Loss)

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016. ACE's Net income for the three months ended June 30, 2017, was higher than the same period in 2016, primarily due to an increase in Revenue net of purchased power expense resulting from higher electric distribution revenues as a result of a distribution rate increase approved by the NJBPU effective August 2016, partially offset by higher Operating and maintenance expense mostly due to an increase in preventive maintenance costs.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016. ACE's Net income (loss) for the six months ended June 30, 2017, was higher than the same period in 2016, primarily due to an increase in Revenue net of purchased power expense resulting from higher electric distribution revenues as a result of a distribution rate increase approved by the NJBPU effective August 2016, lower Operating and maintenance expense mostly due to merger-related costs recognized in March 2016 and a decrease in income tax reserves in the first quarter 2017 for uncertain tax positions related to the deductibility of certain merger commitments.

Revenues Net of Purchased Power Expense

Operating revenues include revenue from the distribution and supply of electricity to ACE's customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that

ACE receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All ACE customers have the choice to purchase electricity from competitive electric generation suppliers. The customer’s choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three and six months ended June 30, 2017, compared to the same periods in 2016, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Electric	51%	49%	50%	48%

Retail customers purchasing electric generation from competitive electric generation suppliers at June 30, 2017 and 2016 consisted of the following:

	June 30, 2017		June 30, 2016	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	92,895	17%	80,325	15%

Operating revenues include revenue from Transition Bond Charges that ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds, revenue from the resale in the PJM wholesale markets for energy and capacity purchased under contacts with unaffiliated NUGs, and revenue from transmission enhancement credits.

Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Purchased power expense consists of the cost of electricity purchased by ACE to fulfill its default electricity supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders.

The changes in ACE’s operating revenue net of purchased power expense for the three and six months ended June 30, 2017 compared to the same periods in 2016 consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)	Six Months Ended June 30, 2017 Increase (Decrease)
Weather	$ —	$ (1)
Volume	2	(4)
Pricing — distribution revenues	10	19
Regulatory required programs	(5)	(10)
Transmission revenues	6	13
Other	—	(2)
Total increase	$ 13	$ 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. During the three months ended June 30, 2017 compared to the same period in 2016, operating revenue net of purchased power and fuel expense remained relatively consistent compared to prior year. During the six months ended June 30, 2017 compared to the same period in 2016, operating revenue net of purchased power and fuel expense was lower due to the impact of slightly unfavorable winter weather conditions in ACE's service territory.

For retail customers of ACE, distribution revenues are not decoupled from the distribution of electricity by ACE, and thus are subject to variability due to changes in customer consumption. Therefore, changes in customer usage (due to weather conditions, energy prices, energy savings programs or other reasons) from period to period have a direct impact on reported distribution revenue for customers in ACE's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in ACE's service territory. The changes in heating and cooling degree days in ACE's service territory for the three and six months ended June 30, 2017 compared to the same periods in 2016 consisted of the following:

				% Change	
Three Months Ended June 30,	**2017**	**2016**	**Normal**	**2017 vs. 2016**	**2017 vs. Normal**
Heating Degree-Days	600	651	806	(7.8)%	(25.6)%
Cooling Degree-Days	324	258	285	25.6%	13.7%
Six Months Ended June 30,					
Heating Degree-Days	2,750	2,921	3,294	(5.9)%	(16.5)%
Cooling Degree-Days	324	261	286	24.1%	13.3%

Volume. During the three months ended June 30, 2017, compared to the same period in 2016, the increase in operating revenue net of purchased power expense related to delivery volume, exclusive of the effects of weather, is primarily due to higher average customer usage. During the six months ended June 30, 2017 compared to the same period in 2016, primarily reflects lower average customer usage, partially offset by the impact of customer growth.

Pricing — Distribution Revenues. The increase in operating revenue net of purchased power expense for the three and six months ended June 30, 2017, compared to the same periods in 2016, was primarily due to the impact of higher electric distribution base rates charged to customers that became effective in August 2016. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. 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. Refer to the depreciation and amortization expense discussion below for additional information on included programs.

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 other billing adjustments. The increase in revenue net of purchased power expense for the three and six months ended June 30, 2017 compared to the same periods in 2016 is a result of higher rates effective June 1, 2017 and June 1, 2016 related to increases in transmission plant investment and operating expenses.

Operating and Maintenance Expense

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Increase (Decrease)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	Increase (Decrease)
Operating and maintenance expense — baseline	$ 77	$ 67	$ 10	$ 150	$ 278	$ (128)
Operating and maintenance expense —regulatory required programs[a]	1	1	—	2	2	—
Total operating and maintenance expense	$ 78	$ 68	$ 10	$ 152	$ 280	$ (128)

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that 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.

The changes in Operating and maintenance expense for the three and six months ended June 30, 2017 compared to the same periods in 2016 consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)	Six Months Ended June 30, 2017 Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ 5	$ 3
Storm-related costs	—	1
BSC and PHISCO allocations[a]	2	(11)
Uncollectible accounts expense	—	(1)
Merger commitments[b]	—	(120)
Other	3	—
Total increase (decrease)	$ 10	$ (128)

(a) Primarily related to merger severance and compensation costs recognized in 2016.
(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions recognized in 2016.

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for the three and six months ended June 30, 2017 compared to the same periods in 2016 consisted of the following:

	Three Months Ended June 30, 2017 Increase (Decrease)	Six Months Ended June 30, 2017 Increase (Decrease)
Depreciation expense[a]	$ 2	$ 3
Regulatory asset amortization[b]	(6)	(12)
Total decrease	$ (4)	$ (9)

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization decreased for the three and six months ended June 30, 2017 compared to the same periods in 2016 as a result of lower revenue due to rate decreases effective October 2016 for the ACE Transition Bond Charge and Market Transition Charge Tax.

Taxes Other Than Income

Taxes other than income for the three and six months ended June 30, 2017 compared to the same periods in 2016, remained relatively constant.

Gain on sales of assets

Gain on sales of assets for the three and six months ended June 30, 2017 compared to the same periods in 2016 remained relatively constant.

Interest Expense, Net

Interest expense, net for the three and six months ended June 30, 2017 compared to the same periods in 2016 remained relatively constant.

Other, Net

Other, net for the three and six months ended June 30, 2017 compared to the same periods in 2016, remained relatively constant.

Effective Income Tax Rate

ACE's effective income tax rate was 33.3% and 40.0% for the three months ended June 30, 2017 and 2016, respectively. ACE's effective income tax rate was (50.0)% and 24.2% for the six months ended June 30, 2017 and 2016, respectively. In the first quarter of 2017, ACE decreased its liability for unrecognized tax benefits by $22 million resulting in a benefit to Income taxes and a corresponding decrease in its effective tax rate. See Note 11 — 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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ACE Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	% Change	Weather - Normal % Change	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	% Change	Weather - Normal % Change
Retail Deliveries[a]								
Residential	814	814	—%	0.2%	1,693	1,752	(3.4)%	(2.3)%
Small commercial & industrial	302	283	6.7%	7.1%	585	572	2.3%	2.8%
Large commercial & industrial	853	853	—%	(0.2)%	1,618	1,673	(3.3)%	(3.5)%
Public authorities & electric railroads	11	9	22.2%	22.2%	24	24	—%	—%
Total retail deliveries	1,980	1,959	1.1%	1.1%	3,920	4,021	(2.5)%	(2.1)%

Number of Electric Customers	As of June 30, 2017	As of June 30, 2016
Residential	486,173	483,044
Small commercial & industrial	61,013	60,928
Large commercial & industrial	3,744	3,806
Public authorities & electric railroads	629	594
Total	551,559	548,372

Electric Revenue	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	% Change	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016	% Change
Retail Sales[a]						
Residential	$ 130	$ 131	(0.8)%	$ 272	$ 281	(3.2)%
Small commercial & industrial	40	39	2.6%	76	78	(2.6)%
Large commercial & industrial	49	50	(2.0)%	94	101	(6.9)%
Public authorities & electric railroads	4	3	33.3%	7	6	16.7%
Total retail	223	223	—%	449	466	(3.6)%
Other revenue[b]	47	47	—%	95	95	—%
Total electric revenue[c]	$ 270	$ 270	—%	$ 544	$ 561	(3.0)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from ACE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from ACE, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.
(c) Includes operating revenues from affiliates totaling $1 million and $1 million for the three months ended June 30, 2017 and 2016, respectively, and $1 million and $2 million for the six months ended June 30, 2017 and 2016, respectively.

Liquidity and Capital Resources

Exelon activity presented below includes the activity of PHI, Pepco, DPL and ACE, from the PHI Merger effective date of March 24, 2016 through June 30, 2017. Exelon prior year activity is unadjusted for the effects of the PHI Merger. Due to the application of push-down accounting to the PHI entity, PHI's activity is presented in two separate reporting periods, the legacy PHI activity through March 23, 2016 (Predecessor), and PHI activity for the remainder of the period after the PHI merger date (Successor). For each of Pepco, DPL and ACE the activity presented below include its activity for the six months ended June 30, 2017 and 2016. 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 $525 million in bilateral facilities with banks which have various expirations between October 2017 and January 2019. 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 further discussion. 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 10 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

NRC Minimum Funding Requirements

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 12—Nuclear Decommissioning to the Combined Notes to Consolidated Financial Statements for additional information on the NRC minimum funding requirements.

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 Exelon to post parental guarantees for Generation's share of the obligations. However, the amount of any required guarantees will ultimately depend on the decommissioning approach adopted at each site, the associated level of costs, and the decommissioning trust 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 discussed in Note 12 — Nuclear Decommissioning, Generation filed its biennial decommissioning funding status report with the NRC on March 31, 2017 and demonstrated adequate funding assurance for all nuclear units currently operating. As of June 30, 2017, TMI passes the NRC minimum funding test based on its shortened estimated life under the most likely SAFSTOR decommissioning approach. Under the most costly decommissioning approach of Delayed DECON, which is currently considered unlikely, a parental guarantee of up to $130 million from Exelon could be required.

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 United States Department of Energy reimbursement agreements or future litigation, across the four alternative decommissioning approaches available, if TMI were to fail to obtain the exemption, Generation could incur spent fuel management and site restoration costs over the next ten years of up to $165 million net of taxes, assuming the SAFSTOR decommissioning scenario, which has the highest non-radiological decommissioning costs and is currently considered the most likely decommissioning approach.

Junior Subordinated Notes

In June 2014, Exelon issued $1.15 billion of junior subordinated notes in the form of 23 million equity units at a stated amount of $50.00 per unit. Each equity unit represented an undivided beneficial ownership interest in Exelon's $1.15 billion of 2.50% junior subordinated notes due in 2024 ("2024 notes") and a forward equity purchase contract. As contemplated in the June 2014 equity unit structure, in April 2017, Exelon completed the remarketing of the 2024 notes into $1.15 billion of 3.497% junior subordinated notes due in 2022 ("Remarketing"). Exelon conducted the Remarketing on behalf of the holders of equity units and did not directly receive any proceeds therefrom. Instead, the former holders of the 2024 notes used debt remarketing proceeds towards settling the forward equity purchase contract with Exelon on June 1, 2017. Exelon issued approximately 33 million shares of common stock from treasury stock and received $1.15 billion upon settlement of the forward equity purchase contract. When reissuing treasury stock Exelon uses the average price paid to repurchase shares to calculate a gain or loss on issuance and records gains or losses directly to retained earnings. A loss on reissuance of treasury shares of $1.05 billion was recorded to retained earnings as of June 30, 2017. See Note 16 — Earnings Per Share and Equity for further information on the issuance of common stock.

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, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 3 — Regulatory Matters and 24 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2016 Form 10-K for further discussion of regulatory and legal proceedings and proposed legislation.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016[(c)]	Variance
Net income	$1,046	$ 430	$ 616
Add (subtract):			
Non-cash operating activities[(a)]	3,273	3,992	(719)
Pension and non-pension postretirement benefit contributions	(325)	(258)	(67)
Income taxes	58	470	(412)
Changes in working capital and other noncurrent assets and liabilities[(b)]	(973)	(781)	(192)
Option premiums (paid) received, net	(8)	(10)	2
Collateral (posted) received, net	(173)	710	(883)
Net cash flows provided by operations	$2,898	$4,553	$(1,655)

(a) Represents, when applicable, depreciation, amortization and accretion, net fair value changes related to derivatives, deferred income taxes, provision for uncollectible accounts, pension and other postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, PHI merger commitment and severance charges, and other non-cash charges. See Note 18—Supplemental Financial Information for further detail on non-cash operating activity.

(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

(c) Includes PHI Consolidated activity from March 24, 2016 to June 30, 2016.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. On August 8, 2014, this funding relief was extended for five years. On November 2, 2015 the funding relief was extended for an additional three years and premiums pension plans pay to the Pension Benefit Guaranty Corporation were further increased.

OPEB funding generally follows accounting cost; however, Exelon's management has historically considered several factors in determining the level of contributions to its funded other postretirement benefit plans, including liabilities management, levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued recovery).

To the extent interest rates decline significantly or the pension plans do not earn the expected asset return rates, annual pension contribution requirements in future years could increase. Additionally, expected contributions could change if Exelon changes its pension or OPEB funding strategy.

Tax Matters

The Registrants' future cash flows from operating activities may be affected by the following tax matters:

- In order to appeal the Tax Court's like-kind exchange decision, Exelon is required to pay the tax, penalties and interest at the time Exelon files its appeal (expected in the second half of 2017). Exelon expects that a payment of approximately $1.3 billion related to the like-kind exchange will be due, including $300 million from ComEd, in the second half of 2017. While Exelon will receive a tax benefit of approximately $350 million associated with the deduction for the interest, Exelon currently has a net operating loss carryforward and thus does not expect to realize the cash benefit until 2018. After taking into account these interest deduction tax benefits, the total estimated net cash outflow for the like-kind exchange is approximately $950 million, of which approximately $300 million is attributable to ComEd after giving consideration to Exelon's agreement to hold ComEd harmless from any unfavorable impacts on ComEd's equity from the like-kind exchange position. ComEd will fund the $300 million with a combination of debt and equity in a manner to maintain its current capital structure.

Of the above amounts payable, Exelon deposited with the IRS $1.25 billion in October of 2016. The remaining amount will be paid in the second half of 2017 at the time Exelon files its appeal of the Tax Court decision. Exelon funded the $1.25 billion deposit with a combination of cash on hand and short-term borrowings.

See Note 11 — Income taxes for discussion of the like-kind exchange tax position.

- State and local governments continue to face increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes or the imposition, extension or permanence of temporary tax levies. In the third quarter of 2017, Illinois increased the corporate income tax rate from 7.75% to 9.5% effective July 1, 2017.

See Note 11 — Income taxes for discussion of the Illinois tax rate change.

Cash flows from operations for the six months ended June 30, 2017 and 2016 by Registrant were as follows:

	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Exelon	$ 2,898	$ 4,553
Generation	974	2,387
ComEd	788	1,128
PECO	368	339
BGE	472	489
Pepco	129	365
DPL	194	220
ACE	77	208

	Successor Six Months Ended June 30, 2017	*Successor* March 24, 2016 to June 30, 2016	*Predecessor* January 1, 2016 to March 23, 2016
PHI	$ 403	$ 188	$ 264

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 six months ended June 30, 2017 and 2016 were as follows:

Generation

- Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on an exchange or in the OTC markets. During the six months ended June 30, 2017 and 2016, Generation had net (payments)/collections of counterparty cash collateral of $(163) million and $720 million, respectively, primarily due to market conditions that resulted in changes to Generation's net mark-to-market position.

- During the six months ended June 30, 2017 and 2016, Generation had net payments of approximately $8 million and $10 million, respectively, related to purchases and sales of options. The level of option activity in a given period may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During six months ended June 30, 2017 and 2016, ComEd posted approximately $13 million and received a return of $10 million of cash collateral with PJM, respectively. ComEd's collateral posted with PJM has increased year over year primarily due to a reduction in ComEd's share of Exelon's unsecured credit with PJM. As of June 30, 2017 and 2016, ComEd had approximately $36 million and $41 million cash collateral posted with PJM, respectively.

For further discussion regarding changes in non-cash operating activities, please refer to Note 18—Supplemental Financial Information of the Combined Notes to the Financial Statements.

Cash Flows from Investing Activities

Cash flows used in investing activities for the six months ended June 30, 2017 and 2016 by Registrant were as follows:

	Six Months Ended June 30,	
	2017	2016
Exelon	$(3,980)	$(10,877)
Generation	(1,357)	(2,210)
ComEd	(1,166)	(1,313)
PECO	(242)	(291)
BGE	(383)	(375)
Pepco	(293)	(307)
DPL	(191)	(180)
ACE	(173)	(160)

	Successor		*Predecessor*
	Six Months Ended June 30, 2017	March 24, 2016 to June 30, 2016	January 1, 2016 to March 23, 2016
PHI	$ (667)	$ (350)	$ (343)

Significant investing cash flow impacts for the Registrants for six months ended June 30, 2017 and 2016 were as follows:

Exelon

- During the six months ended June 30, 2017, Exelon had expenditures of $23 million and $182 million relating to the acquisitions of ConEdison Solutions and the FitzPatrick facility, respectively. During the six months ended June 30, 2016 , Exelon had expenditures of $6.6 billion relating to the acquisition of PHI.
- During the six months ended June 30, 2016, Exelon had proceeds of $360 million as a result of early termination of direct financing leases.

Generation

- During the six months ended June 30, 2017, Exelon had expenditures of $23 million and $182 million relating to the acquisitions of ConEdison Solutions and the FitzPatrick facility, respectively.

Capital Expenditure Spending

Generation

Generation has entered into several agreements to acquire equity interests in privately held and development stage entities which develop energy-related technologies. The agreements contain a series of scheduled investment commitments, including in-kind service contributions. There are anticipated expenditures remaining through 2019 to fund anticipated planned capital and operating needs of the associated companies. See Note 24 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2016 Form 10-K for further details of Generation's equity interests.

Capital expenditures by Registrant for the six months ended June 30, 2017 and 2016 and projected amounts for the full year 2017 are as follows:

	Projected Full Year 2017[(a)]	Six Months Ended June 30,	
		2017	2016
Exelon[(b)]	$ 8,150	3,845	$4,489
Generation	2,525	1,189	2,051
ComEd[(c)]	2,200	1,168	1,334
PECO	775	367	299
BGE	925	405	392
Pepco	600	291	256
DPL	400	192	182
ACE	325	175	164

	Projected Full Year 2017 [(a)]	*Successor*		*Predecessor*
		Six Months Ended June 30, 2017	March 24, 2016 to June 30, 2016	January 1, 2016 to March 23, 2016
PHI[(d)]	$ 1,375	$ 671	$ 339	$ 273

(a) Total projected capital expenditures do not include adjustments for non-cash activity.
(b) Includes corporate operations, BSC, and PHISCO rounded to the nearest $25 million.
(c) The 2017 projections include approximately $279 million of expected incremental spending pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten year period, through 2022, to modernize and storm-harden its distribution system and to implement smart grid technology.
(d) Includes PHISCO rounded to the nearest $25 million.

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

Generation

Approximately 37% and 21% of the projected 2017 capital expenditures at Generation are for the acquisition of nuclear fuel and growth (primarily new plant construction and distributed generation), respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Generation anticipates that they will fund capital expenditures with internally generated funds and borrowings.

ComEd, PECO, BGE, Pepco, DPL and ACE

Approximately 92% of the projected 2017 capital expenditures at ComEd and 100% of the projected of the projected 2017 capital expenditures at PECO, BGE, Pepco, DPL, and ACE are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA, and the Utility Registrants' construction commitments under PJM's RTEP. In addition to the capital expenditure for continuing projects, ComEd's total expenditures include smart grid/smart meter technology required under EIMA.

The Utility Registrants as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments could require the Utility Registrants to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards. In 2010, NERC provided guidance to transmission owners that recommended the Utility Registrants perform assessments of their transmission lines. ComEd, PECO and BGE submitted their final bi-annual reports to NERC in January 2014. ComEd, PECO and BGE will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2017 capital expenditures above reflect capital spending for remediation to be completed through 2018. Pepco, DPL and ACE have substantially completed their assessments and thus do not expect significant capital expenditures related to this guidance in 2017.

The Utility Registrants anticipate that they will fund their capital expenditures with a combination of internally generated funds and borrowings and additional capital contributions from parent, including ComEd's capital expenditures associated with EIMA as further discussed in Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the six months ended June 30, 2017 and 2016 by Registrant were as follows:

	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Exelon	$ 983	$1,469
Generation	358	(235)
ComEd	361	854
PECO	(144)	(140)
BGE	(100)	(118)
Pepco	274	64
DPL	(43)	(30)
ACE	2	100

	Successor		*Predecessor*
	Six Months Ended June 30, 2017	**March 24, 2016 to June 30, 2016**	**January 1, 2016 to March 23, 2016**
PHI	$ 245	$ 137	$ 372

Debt

See Note 10 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants' debt issuances.

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Dividends

Cash dividend payments and distributions during the six months ended June 30, 2017 and 2016 by Registrant were as follows:

	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Exelon	$ 607	$ 582
Generation	330	111
ComEd	211	183
PECO	144	139
BGE[(a)]	99	96
Pepco	58	55
DPL	54	38
ACE	22	11

	Successor		*Predecessor*
	Six Months Ended June 30, 2017	March 24, 2016 to June 30, 2016	January 1, 2016 to March 23, 2016
PHI	$ 131	$ 124	$ —

(a) Includes dividends paid on BGE's preference stock in 2016.

Quarterly dividends declared by the Exelon Board of Directors during the six months ended June 30, 2017 and for the third quarter of 2017 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share[(a)]
First Quarter 2017	January 31, 2017	February 15, 2017	March 10, 2017	$0.3275
Second Quarter 2017	April 25, 2017	May 15, 2017	June 9, 2017	$0.3275
Third Quarter 2017	July 25, 2017	August 15, 2017	September 8, 2017	$0.3275

(a) Exelon's Board of Directors approved a revised dividend policy. The approved policy will raise the dividend 2.5% each year for the next three years, beginning with the June 2016 dividend and subject to Board approval.

Short-Term Borrowings

Short-term borrowings incurred (repaid) during the six months ended June 30, 2017 and 2016 by Registrant were as follows:

	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Exelon	$ 488	$ (919)
Generation	15	179
ComEd	389	(259)
BGE	40	(2)
Pepco	(23)	(64)
DPL	25	(105)
ACE	42	(5)

	Successor		*Predecessor*
	Six Months Ended June 30, 2017	March 24, 2016 to June 30, 2016	January 1, 2016 to March 23, 2016
PHI	$ (455)	$ (837)	$ 379

Contributions from Parent/Member

Contributions received from Parent/Member for the six months ended June 30, 2017 and 2016 by Registrant were as follows:

	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Generation	$ —	$ 45
ComEd [(a)(b)]	184	113
BGE [(b)]	—	21
Pepco [(c)]	161	187
DPL [(c)]	—	113
ACE [(c)]	—	139

	Successor: Six Months Ended June 30, 2017	Successor: March 24, 2016 to June 30, 2016	Predecessor: January 1, 2016 to March 23, 2016
PHI [(b)]	$ 751	$ 1,088	$ —

(a) Additional contributions from parent or external debt financing may be required as a result of increased capital investment in infrastructure improvements and modernization pursuant to EIMA and transmission upgrades.
(b) Contribution paid by Exelon.
(c) Contribution paid by PHI

Other

For the six months ended June 30, 2017, other financing activities primarily consist of debt issuance costs. See Note 10 — Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for further details 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 $9.5 billion in aggregate total commitments of which $8.2 billion was available as of June 30, 2017, and of which no financial institution has more than 7% of the aggregate commitments for the Registrants. The Registrants had access to the commercial paper market during the second quarter of 2017 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A. RISK FACTORS of the Exelon 2016 Form 10-K for further 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 June 30, 2017, it would have been required to provide incremental collateral of $1.8 billion to meet collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within its current available credit facility capacities of $4.5 billion.

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 June 30, 2017 and available credit facility capacity prior to any incremental collateral at June 30, 2017:

	PJM Credit Policy Collateral	Other Incremental Collateral Required (a)	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 17	$ —	$ 998
PECO	3	21	598
BGE	3	36	600
Pepco	5	—	300
DPL	3	10	300
ACE	—	—	300

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

Exelon Credit Facilities

Exelon, Pepco, DPL and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and short-term notes. ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. PHI 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.

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at June 30, 2017:

Commercial Paper Programs

Commercial Paper Issuer	Maximum Program Size (a)(b)	Outstanding Commercial Paper at June 30, 2017	Average Interest Rate on Commercial Paper Borrowings for the Six Months Ended June 30, 2017
Exelon Corporate	$ 600	$ —	1.16%
Generation	5,300	569	1.15%
ComEd	1,000	389	1.17%
PECO	600	—	1.13%
BGE	600	85	1.07%
Pepco	500	—	1.04%
DPL	500	25	1.40%
ACE	350	42	1.28%

(a) Excludes $525 million bilateral credit facilities that do not back Generation's commercial paper program.
(b) Excludes additional credit facility agreements for Generation, ComEd, PECO, BGE, Pepco, DPL and ACE with aggregate commitments of $50 million, $34 million, $34 million, $5 million, $2 million, $2 million and $2 million, respectively, arranged with minority and community banks located primarily within utilities' service territories. These facilities expire on October 13, 2017. These facilities are solely utilized to issue letters of credit. As of June 30, 2017, letters of credit issued under these agreements for Generation, ComEd, PECO and BGE totaled $5 million, $12 million, $21 million and $2 million, respectively.

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of its commercial paper outstanding does not reduce available capacity under a Registrant's credit facility, a Registrant does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit facility. At June 30, 2017, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit facilities:

Credit Agreements

					Available Capacity at June 30, 2017	
Borrower	Facility Type	Aggregate Bank Commitment[(a)(b)(c)]	Facility Draws	Outstanding Letters of Credit	Actual	To Support Additional Commercial Paper[(b)(d)]
Exelon Corporate	Syndicated Revolver	$ 600	$ —	$ 45	$ 555	$ 555
Generation[(e)]	Syndicated Revolver	5,300	—	887	4,413	3,844
Generation	Bilaterals	525	130	285	110	—
ComEd	Syndicated Revolver	1,000	—	2	998	609
PECO	Syndicated Revolver	600	—	2	598	598
BGE	Syndicated Revolver	600	—	—	600	515
Pepco	Syndicated Revolver	300	—	—	300	300
DPL	Syndicated Revolver	300	—	—	300	275
ACE	Syndicated Revolver	300	—	—	300	258

(a) Excludes $129 million of credit facility agreements arranged at minority and community banks at Generation, ComEd, PECO, BGE, Pepco, DPL and ACE. These facilities expire on October 13, 2017. These facilities are solely utilized to issue letters of credit. As of June 30, 2017, letters of credit issued under these agreements for Generation, ComEd, PECO and BGE totaled $5 million, $12 million, $21 million and $2 million, respectively.
(b) Pepco, DPL and ACE's revolving credit facility is subject to available borrowing capacity. The borrowing capacity may be increased or decreased during the term of the facility, except that (i) the sum of the borrowing capacity must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by each of Pepco, DPL or ACE may not exceed $900 million or the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the borrowing reallocations may not exceed eight per year during the term of the facility
(c) Excludes nonrecourse debt letters of credit, see Note 14 — Debt and Credit Agreements in the Exelon 2016 Form 10-K for further information on Continental Wind nonrecourse debt.
(d) Excludes $525 million bilateral credit facilities that do not back Generation's commercial paper program.
(e) Excludes ExGen Texas Power Financing's $15 million of borrowed debt on its revolving credit facility.

As of June 30, 2017, there was $130 million of borrowings under Generation's bilateral credit facilities.

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's, BGE's, Pepco's, DPL's, and ACE's revolving credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular Registrant's credit rating. The adders for the prime based borrowings and LIBOR-based borrowings are presented in the following table:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Prime based borrowings	27.5	27.5	7.5	0.0	0.0	7.5	7.5	7.5
LIBOR-based borrowings	127.5	127.5	107.5	90.0	100.0	107.5	107.5	107.5

The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 90 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments. The fee varies depending upon the respective credit ratings of the borrower.

Each revolving credit agreement for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The following table summarizes the minimum thresholds reflected in the credit agreements for the six months ended June 30, 2017:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At June 30, 2017, the interest coverage ratios at Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE were as follows:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Interest coverage ratio	6.26	9.87	6.94	8.60	10.61	6.97	8.92	6.22

An event of default under Exelon, Generation, ComEd, PECO or BGE's indebtedness will not constitute an event of default under any of the others' credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation will constitute an event of default under the Exelon Corporate credit facility. An event of default under Pepco, DPL or ACE's indebtedness will not constitute an event of default under any of the others' credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $50 million in the aggregate will constitute an event of default under the credit facility.

The absence of a material adverse change in Exelon's or PHI's business, property, results of operations or financial condition is not a condition to the availability of credit under the credit agreement. The credit agreement does not include any rating triggers.

Security Ratings

The Registrants' access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants' borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant's securities could increase fees and interest charges under that Registrant's credit agreements.

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 9 — 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 intercompany money pools. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of June 30, 2017, are presented in the following table:

Exelon Intercompany Money Pool	**During the Three Months Ended June 30, 2017**		**As of June 30, 2017**
Contributed (borrowed)	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
Exelon Corporate	$ 558	n/a	$ 506
Generation	20	(294)	(251)
PECO	26	(20)	10
BSC	—	(389)	(319)
PHI Corporate [(a)]	n/a	(34)	—
PCI [(a)]	54	—	54

(a) As a result of the merger, PHI Corporate and PCI began to participate in the Exelon Intercompany Money Pool effective March 24, 2016.

PHI Intercompany Money Pool	**During the Three Months Ended June 30, 2017**		**As of June 30, 2017**
Contributed (borrowed)	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
PHI Corporate	$ 49	$ (3)	$ 12
Pepco	—	—	—
DPL	—	—	—
ACE	—	—	—
PHISCO	3	(51)	(11)

Investments in Nuclear Decommissioning Trust Funds

Exelon, Generation and CENG maintain trust funds, as required by the NRC, to fund certain costs of decommissioning nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation’s NDT fund investment policy. Generation’s and CENG’s investment policies establish limits on the concentration of holdings in any one company and also in any one industry. See Note 12 —Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC’s minimum funding requirements and related liquidity ramifications.

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.

Regulatory Authorizations

Generation, 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:

	Short-term Financing Authority[a]			Long-term Financing Authority		
	Commission	Expiration Date	Amount (in millions)	Commission	Expiration Date	Amount (in millions)
ComEd[b]	FERC	December 31, 2017	$ 2,500	ICC	2019	$ 2,383
PECO	FERC	December 31, 2017	1,500	PAPUC	December 31, 2018	1,600
BGE	FERC	December 31, 2017	700	MDPSC	N/A	1,000
Pepco	FERC	June 30, 2018	500	MDPSC / DCPSC	September 25, 2017	350
DPL	FERC	June 30, 2018	500	MDPSC / DPSC	December 31, 2017	125
ACE	NJPU	January 1, 2018	350	NJBPU	December 31, 2017	300

(a) Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.
(b) ComEd had $1,565 million available in long-term debt refinancing authority and $818 million available in new money long term debt financing authority from the ICC as of June 30, 2017 and has an expiration date of June 1, 2019 and March 1, 2019, respectively.

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 24 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in the Exelon 2016 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, PECO, and BGE 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 — Basis of Presentation of the Combined Notes to Consolidated Financial Statements for further 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 2016 Form 10-K and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Contractual Obligations and Commercial Commitments."

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 2016 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 amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel and other commodities.

Generation

Normal Operations and Hedging Activities. 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 price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including forwards, futures, swaps and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2017 through 2019.

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 risk for Exelon's expected generation, typically on a ratable basis over a three-year period. As of June 30, 2017, the percentage of expected generation hedged for the major reportable segments is 96%-99%, 71%-74% and 39%-42% for 2017, 2018 and 2019, 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, which include economic hedges and certain non-derivative contracts including Generation's sales to the Utility Registrants 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 non-proprietary trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on June 30, 2017 market conditions and hedged position would have an immaterial impact on pre-tax net income for 2017 and decreases of approximately $230 million and $560 million, respectively, for 2018 and 2019. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage 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.

Proprietary Trading Activities. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into 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, including volume, stop loss and Value-at-Risk (VaR) 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, which included physical volumes of 2,312 GWhs and 4,162 GWhs for the three and six months ended June 30, 2017, respectively, and 1,289 GWhs and 2,509 GWhs and for the three and six months June 30, 2016, respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Proprietary trading portfolio activity for the six months ended June 30, 2017 resulted in $7 million of pre-tax gains due to net mark-to-market losses of $2 million and realized gains of $9 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period and a one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $0.3 million of exposure during the quarter. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation's total Revenue net of purchase power and fuel expense for the six months ended June 30, 2017 of $4,106 million.

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 51% of Generation's uranium concentrate requirements from 2017 through 2021 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 results of operations, cash flows and financial positions.

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. See Note 5 — Regulatory Matters and Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives. ComEd does not enter into derivatives for speculative or proprietary trading purposes.

PECO

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements. PECO has 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. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

PECO has also entered into 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 its long-term price risk in the natural gas market. PECO's hedging program for natural gas procurement has no direct impact on its financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

BGE

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE's MDPSC-approved SOS program. BGE's full requirements contracts that are considered derivatives 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. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component.

BGE has also entered into natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE's financial position. However, under BGE's market-based rates incentive 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 does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Pepco

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 price risk related to electric supply procurement is limited. Pepco locks in fixed prices for all of 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.

Pepco does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

DPL

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 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 all of its SOS requirements through full requirements contracts. DPL's 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 a GCR mechanism approved by the DPSC. 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.

DPL does not enter into derivatives for speculative or proprietary trading purposes. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

ACE

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 price risk related to electric supply procurement is limited. ACE locks in fixed prices for all of its BGS requirements through full requirements contracts. 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.

ACE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities. The following detailed presentation of Exelon's, Generation's, ComEd's, PHI's and DPL's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon's, Generation's, ComEd's, PHI's and DPL's commodity mark-to-market net asset or liability balance sheet position from December 31, 2016 to June 30, 2017. 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 normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 9 — 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 June 30, 2017 and December 31, 2016.

	Exelon	Generation	ComEd	PHI	DPL
Total mark-to-market energy contract net assets (liabilities) at December 31, 2016[(a)]	$ 719	$ 977	$ (258)	$—	$—
Total change in fair value during 2017 of contracts recorded in results of operations	(200)	(200)	—	—	—
Reclassification to realized of contracts recorded in results of operations	(31)	(31)	—	—	—
Contracts received at acquisition date	—	—	—	—	—
Changes in fair value — recorded through regulatory assets and liabilities[(b)]	—	—	2	(2)	(2)
Changes in allocated collateral	158	156	—	2	2
Changes in net option premium paid/(received)	8	8	—	—	—
Option premium amortization	(11)	(11)	—	—	—
Upfront payments and amortizations[(c)]	(15)	(15)	—	—	—
Total mark-to-market energy contract net assets (liabilities) at June 30, 2017[(a)]	$ 628	$ 884	$ (256)	$—	$—

(a) Amounts are shown net of collateral paid to and received from counterparties.

(b) For ComEd and DPL, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of June 30, 2017, ComEd recorded a regulatory liability of $256 million related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. For the six months ended June 30, 2017, ComEd also recorded $5 million of decreases in fair value and an increase for realized losses due to settlements of $7 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 amortization.

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 8 — Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2017	2018	2019	2020	2021	2022 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[a][b]:							
Actively quoted prices (Level 1)	$ 69	$ (11)	$(37)	$(14)	$ 2	$ (4)	$ 5
Prices provided by external sources (Level 2)	173	111	5	(4)	5	—	290
Prices based on model or other valuation methods (Level 3)[c]	144	252	94	16	(29)	(144)	333
Total	$386	$352	$ 62	$ (2)	$(22)	$ (148)	$ 628

(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 $485 million at June 30, 2017.
(c) Includes ComEd's net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2017	2018	2019	2020	2021	2022 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[a][b]:							
Actively quoted prices (Level 1)	$ 69	$ (11)	$ (37)	$(14)	$ 2	$ (4)	$ 5
Prices provided by external sources (Level 2)	173	111	5	(4)	5	—	290
Prices based on model or other valuation methods (Level 3)	154	272	115	36	(9)	21	589
Total	$396	$372	$ 83	$ 18	$ (2)	$ 17	$ 884

(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 $485 million at June 30, 2017.

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ComEd

	Maturities Within						
	2017	2018	2019	2020	2021	2022 and Beyond	Total Fair Value
Commodity derivative contracts(a):							
Prices based on model or other valuation methods (Level 3)	$(10)	$(20)	$(21)	$(20)	$(20)	$ (165)	$ (256)

(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 enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a 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 purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of June 30, 2017. 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, NYMEX, ICE, NASDAQ, NGX and Nodal 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 $23 million, $27 million, $21 million, $41 million, $12 million, and $6 million as of June 30, 2017, respectively.

Rating as of June 30, 2017	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	$ 878	$ 14	$ 864	1	$ 299
Non-investment grade	47	1	46	—	—
No external ratings					
Internally rated — investment grade	327	—	327	—	—
Internally rated — non-investment grade	123	14	109	—	—
Total	$ 1,375	$ 29	$ 1,346	1	$ 299

Rating as of June 30, 2017	Maturity of Credit Risk Exposure Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 719	$ 161	$ (2)	$ 878
Non-investment grade	34	13	—	47
No external ratings				
Internally rated — investment grade	273	34	20	327
Internally rated — non-investment grade	99	24	—	123
Total	$ 1,125	$ 232	$ 18	$ 1,375

Net Credit Exposure by Type of Counterparty	As of June 30, 2017
Financial institutions	$ 89
Investor-owned utilities, marketers, power producers	563
Energy cooperatives and municipalities	560
Other	134
Total	$ 1,346

(a) As of June 30, 2017, credit collateral held from counterparties where Generation had credit exposure included $19 million of cash and $10 million of letters of credit.

ComEd, PECO, BGE, PHI, Pepco, DPL and ACE

There have been no significant changes or additions to ComEd's, PECO's, BGE's, PHI's, Pepco's, DPL's or ACE's exposures to credit risk that are described in ITEM 1A. RISK FACTORS of Exelon's 2016 Annual Report on Form 10-K.

See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for 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. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. 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. 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. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

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 results of operations, cash flows and financial position. 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. In order to post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See Liquidity and Capital Resources — Credit Matters — Exelon Credit Facilities for additional information.

As of June 30, 2017, Generation had cash collateral of $517 million posted and cash collateral held of $34 million for external counterparties with derivative positions, of which $485 million and an immaterial amount in net cash collateral deposits were offset against energy derivative and interest rate and foreign exchange derivative related to underlying energy contracts, respectively. As of June 30, 2017, $2 million of cash collateral held was not offset against net derivative positions because it was not associated with energy-related derivatives or as of the balance sheet date there were no positions to offset. See Note 17 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of June 30, 2017, ComEd held $13 million in collateral from suppliers in association with energy procurement contracts and held approximately $19 million in the form of cash and letters of credit for both annual and long-term renewable energy contracts. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements in this report and Note 3 — Regulatory Matters of the 2016 Exelon Form 10-K for additional information.

PECO

As of June 30, 2017, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

BGE

BGE is not required to post collateral under its electric supply contracts nor was it holding collateral under its electric supply procurement contracts as of June 30, 2017. As of June 30, 2017, 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. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Pepco

Pepco is not required to post collateral under its energy procurement contracts. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

DPL

DPL is not required to post collateral under its energy procurement contracts. As of June 30, 2017, DPL was not required to post collateral under its natural gas procurement contracts. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

ACE

ACE is not required to post collateral under its energy procurement contracts. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

RTOs and ISOs (All Registrants)

Generation, ComEd, PECO, BGE, Pepco, DPL and ACE 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. 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 are no spot energy markets, 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. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

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 fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At June 30, 2017, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $492 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $3 million decrease in Exelon Consolidated pre-tax income for the six months ended June 30, 2017. 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.

Equity Price Risk (Exelon and Generation)

Generation maintains trust funds, as required by the NRC, to fund certain costs of decommissioning its nuclear plants. As of June 30, 2017, Generation's decommissioning trust funds are reflected at fair value on 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 $621 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 further discussion of equity price risk as a result of the current capital and credit market conditions.

Item 4. Controls and Procedures

During the second quarter of 2017, 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 June 30, 2017, 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. There have been no changes in internal control over financial reporting that occurred during the second quarter of 2017 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 2016 Form 10-K and (b) Notes 5 — Regulatory Matters and 17 — 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 June 30, 2017, the Registrants' risk factors were consistent with the risk factors described in the Registrants' combined 2016 Form 10-K in ITEM 1A. RISK FACTORS.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Sales of Unregistered Securities

Exelon sponsors several 401(k) retirement savings plans that are made available to different groups of its employees. The plans generally allow participating employees to make contributions from their eligible pay, and Exelon provides both a fixed and annual profit-sharing match. Exelon, acting through the Exelon Investment Office, is responsible for the selection and retention of the plans' respective investment options and any investment manager that may be appointed under the Exelon Corporation Defined Contribution Retirement Plans Master Trust (the Master Trust). The plans' investments are held in the Master Trust. Plan investments are fully participant-directed. The investment options include a menu of funds, some of which may include Exelon common stock. For participants who elect an allocation for purchases of Exelon common stock, the Master Trust through an investment manager acquires Exelon common stock in the open market and allocates that stock to the account of each such participant. It is the position of the SEC that the plans are considered to be an affiliate of Exelon because Exelon is the sponsor of each plan and the plan administrator, acting through an employee of Exelon.

Effective January 1, 2016, the Exelon Employee Savings Plan for Represented Employees at TMI and Oyster Creek (the TMI/OC 401(k)) and the Exelon Employee Savings Plan for Represented Employees at Clinton (the Clinton 401(k)) each made an Exelon common stock fund available as an investment option for the first time. From January 1, 2016 through May 2017, participants in the TMI/OC 401(k) and the Clinton 401(k) acquired approximately 55,250 and 58,500 equivalent shares of Exelon common stock, respectively, that were not properly registered due to an inadvertent failure to file a registration statement on Form S-8 relating to the allocation of such shares to the participants' accounts in such plans.

The discovery of the failure to file a registration statement on Form S-8 for the TMI/OC 401(k) and the Clinton 401(k) prompted Exelon to review the amount of shares issued under the Exelon Employee Savings Plan (the ESP), a 401(k) retirement savings plan made available to most Exelon employees. Exelon previously filed registration statements registering shares for the ESP, including 6.2 million shares (on a post-split basis) registered in 2000 when the ESP began offering Exelon shares upon the merger that created Exelon and 5.6 million shares registered in 2012 after the merger of Constellation Energy Group, Inc. into Exelon and the merger of the Constellation Energy Group, Inc. Employee Savings Plan into the ESP. Upon review, Exelon determined that the volume of transactions in the Exelon stock fund in the ESP may have exceeded the number of shares that had been previously registered. While Exelon was unable to obtain records from the previous recordkeeper for the period from 2000 through 2008, during the period from 2009 through 2016, approximately 51 million shares of Exelon common stock were acquired by participants through the ESP, including approximately 9 million shares in 2016, that may not have been properly registered due to an inadvertent failure to file a registration statement on Form S-8.

On June 29, 2017, Exelon filed a registration statement on Form S-8 to (1) register transactions by the TMI/OC 401(k) and the Clinton 401(k) after that date and to register potential resales by plan participants who purchased shares through their accounts in the period between January 1, 2016 and the date of the filing of the registration statement, and (2) register transactions by the ESP after that date and to register potential resales by plan participants who purchased shares through their accounts prior to the date of the filing of the registration statement. The registration statement also registered 5,000,000 additional shares for the Exelon 2011 Long-Term Incentive Plan that was approved by shareholders in 2010; there were no sales of unregistered shares of Exelon common stock or other forms of Exelon equity through that plan. Exelon did not receive any proceeds from the sales of the securities pursuant to any of the 401(k) plans because the shares were purchased in the open market by a third party administrator on behalf of the Master Trust. For the period during which unregistered issuances of Exelon common stock through the 401(k) plans may have occurred, Exelon has filed in a timely manner all annual reports on Form 11-K with respect to each of the 401(k) plans, filed in a timely manner all annual reports on Form 10-K and quarterly reports on Form 10-Q with respect to Exelon, and maintained and distributed to participants in the 401(k) plans a summary plan description with respect to the respective 401(k) plan as required by the Employee Retirement Income Security Act of 1974, as amended. Based on the current market price of Exelon stock Exelon does not anticipate that any participants in any of the 401(k) plans who still hold shares acquired within the last year will seek rescission. These shares have always been treated as outstanding for financial reporting purposes, and Exelon does not expect that the overall effect of any issuance of unregistered shares, including the exercise of any applicable rescission rights by participants, will have a material impact on Exelon’s results of operations, financial position, or cash flows. Exelon is implementing additional controls to ensure that any shares of Exelon common stock sold pursuant to the 401(k) plans will be registered in accordance with the registration requirements of the Securities Act of 1933, as amended.

Item 4. Mine Safety Disclosures

All Registrants

Not applicable to the Registrants.

Item 6. Exhibits

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
4.1	Supplemental Indenture, dated as of May 15, 2017, from Potomac Electric Power Company to The Bank of New York Mellon, as trustee (File No. 001-01072, Form 8-K dated May 22, 2017, Exhibit 4.2)
4.2	Form of First Mortgage Bond, 4.15% Series due March 15, 2043 (File No. 001-01072, Form 8-K dated May 22, 2017, Exhibit 4.3)
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 June 30, 2017 filed by the following officers for the following companies:

31-1	— Filed by Christopher M. Crane for Exelon Corporation
31-2	— Filed by Jonathan W. Thayer 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 Anne R. Pramaggiore for Commonwealth Edison Company
31-6	— Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
31-7	— Filed by Craig L. Adams for PECO Energy Company
31-8	— Filed by Phillip S. Barnett 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 Donna J. Kinzel for Pepco Holdings LLC
31-13	— Filed by David M. Velazquez for Potomac Electric Power Company
31-14	— Filed by Donna J. Kinzel for Potomac Electric Power Company
31-15	— Filed by David M. Velazquez for Delmarva Power & Light Company
31-16	— Filed by Donna J. Kinzel for Delmarva Power & Light Company
31-17	— Filed by David M. Velazquez for Atlantic City Electric Company
31-18	— Filed by Donna J. Kinzel for Atlantic City Electric Company

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes — Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2017 filed by the following officers for the following companies:

32-1	— Filed by Christopher M. Crane for Exelon Corporation
32-2	— Filed by Jonathan W. Thayer 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 Anne R. Pramaggiore for Commonwealth Edison Company
32-6	— Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
32-7	— Filed by Craig L. Adams for PECO Energy Company
32-8	— Filed by Phillip S. Barnett 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 Donna J. Kinzel for Pepco Holdings LLC
32-13	— Filed by David M. Velazquez for Potomac Electric Power Company
32-14	— Filed by Donna J. Kinzel for Potomac Electric Power Company
32-15	— Filed by David M. Velazquez for Delmarva Power & Light Company
32-16	— Filed by Donna J. Kinzel for Delmarva Power & Light Company
32-17	— Filed by David M. Velazquez for Atlantic City Electric Company
32-18	— Filed by Donna J. Kinzel 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	/s/ Jonathan W. Thayer
Christopher M. Crane President and Chief Executive Officer (Principal Executive Officer) and Director	Jonathan W. Thayer Senior Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Duane M. DesParte	
Duane M. DesParte Senior Vice President and Corporate Controller (Principal Accounting Officer)	

August 2, 2017

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 President and Chief Executive Officer (Principal Executive Officer)	Bryan P. Wright Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Matthew N. Bauer	
Matthew N. Bauer Vice President and Controller (Principal Accounting Officer)	

August 2, 2017

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/ Anne R. Pramaggiore	/s/ Joseph R. Trpik, Jr.
Anne R. Pramaggiore President and Chief Executive Officer (Principal Executive Officer)	Joseph R. Trpik, Jr. 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)	

August 2, 2017

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/ Craig L. Adams	/s/ Phillip S. Barnett
Craig L. Adams President and Chief Executive Officer (Principal Executive Officer) and Director	Phillip S. Barnett Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Scott A. Bailey	
Scott A. Bailey Vice President and Controller (Principal Accounting Officer)	

August 2, 2017

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. Chief Executive Officer (Principal Executive Officer)	David M. Vahos 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)	

August 2, 2017

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/ Donna J. Kinzel
David M. Velazquez President and Chief Executive Officer (Principal Executive Officer)	Donna J. Kinzel Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Robert M. Aiken	
Robert M. Aiken Vice President and Controller (Principal Accounting Officer)	

August 2, 2017

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/ Donna J. Kinzel
David M. Velazquez President and Chief Executive Officer (Principal Executive Officer)	Donna J. Kinzel Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Robert M. Aiken	
Robert M. Aiken Vice President and Controller (Principal Accounting Officer)	

August 2, 2017

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/ Donna J. Kinzel
David M. Velazquez President and Chief Executive Officer (Principal Executive Officer)	Donna J. Kinzel Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Robert M. Aiken	
Robert M. Aiken Vice President and Controller (Principal Accounting Officer)	

August 2, 2017

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/ Donna J. Kinzel
David M. Velazquez President and Chief Executive Officer (Principal Executive Officer)	Donna J. Kinzel Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Robert M. Aiken	
Robert M. Aiken Vice President and Controller (Principal Accounting Officer)	

August 2, 2017

Exhibit 31-1

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Christopher M. Crane, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ CHRISTOPHER M. CRANE
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 2, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Jonathan W. Thayer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ JONATHAN W. THAYER
Senior Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: August 2, 2017

Exhibit 31-3

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. Cornew, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ KENNETH W. CORNEW

President and Chief Executive Officer
(Principal Executive Officer)

Date: August 2, 2017

Exhibit 31-4

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Bryan P. Wright, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ BRYAN P. WRIGHT
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: August 2, 2017

Exhibit 31-5

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Anne R. Pramaggiore, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ ANNE R. PRAMAGGIORE
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 2, 2017

Exhibit 31-6

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Joseph R. Trpik, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ JOSEPH R. TRPIK, JR.
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: August 2, 2017

Exhibit 31-7

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Craig L. Adams, certify that:

1. I have reviewed this quarterly report on Form 10-Q of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ CRAIG L. ADAMS

President and Chief Executive Officer
(Principal Executive Officer)

Date: August 2, 2017

Exhibit 31-8

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Phillip S. Barnett, certify that:

1. I have reviewed this quarterly report on Form 10-Q of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ PHILLIP S. BARNETT

Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: August 2, 2017

Exhibit 31-9

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Calvin G. Butler, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ CALVIN G. BUTLER, JR.
Chief Executive Officer
(Principal Executive Officer)

Date: August 2, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Vahos, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

/S/ DAVID M. VAHOS

Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: August 2, 2017

Exhibit 31-11

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Velazquez, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Pepco Holdings LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ DAVID M. VELAZQUEZ
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 2, 2017

Exhibit 31-12

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Donna J. Kinzel, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Pepco Holdings LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ DONNA J. KINZEL

Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: August 2, 2017

Exhibit 31-13

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Velazquez, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Potomac Electric Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ DAVID M. VELAZQUEZ

President and Chief Executive Officer
(Principal Executive Officer)

Date: August 2, 2017

Exhibit 31-14

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Donna J. Kinzel, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Potomac Electric Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DONNA J. KINZEL

Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: August 2, 2017

Exhibit 31-15

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Velazquez, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Delmarva Power & Light Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

/S/ DAVID M. VELAZQUEZ
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 2, 2017

Exhibit 31-16

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Donna J. Kinzel, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Delmarva Power & Light Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ DONNA J. KINZEL

Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: August 2, 2017

Exhibit 31-17

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Velazquez, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Atlantic City Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ DAVID M. VELAZQUEZ
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 2, 2017

Exhibit 31-18

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Donna J. Kinzel, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Atlantic City Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ DONNA J. KINZEL
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: August 2, 2017

Exhibit 32-1

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Corporation for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/S/ CHRISTOPHER M. CRANE

Christopher M. Crane
President and Chief Executive Officer

Date: August 2, 2017

Exhibit 32-2

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Corporation for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/S/ JONATHAN W. THAYER

Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer

Date: August 2, 2017

Exhibit 32-3

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Generation Company, LLC for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/S/ KENNETH W. CORNEW

Kenneth W. Cornew
President and Chief Executive Officer

Date: August 2, 2017

Exhibit 32-4

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Generation Company, LLC for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/S/ BRYAN P. WRIGHT

Bryan P. Wright
Senior Vice President and Chief Financial Officer

Date: August 2, 2017

Exhibit 32-5

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/S/ ANNE R. PRAMAGGIORE

Anne R. Pramaggiore
President and Chief Executive Officer

Date: August 2, 2017

Exhibit 32-6

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/S/ JOSEPH R. TRPIK, JR.

Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Date: August 2, 2017

Exhibit 32-7

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of PECO Energy Company for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/S/ CRAIG L. ADAMS

Craig L. Adams
President and Chief Executive Officer

Date: August 2, 2017

Exhibit 32-8

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of PECO Energy Company for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/S/ PHILLIP S. BARNETT

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer

Date: August 2, 2017

Exhibit 32-9

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Baltimore Gas and Electric Company for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/S/ CALVIN G. BUTLER, JR.

Calvin G. Butler, Jr.
Chief Executive Officer

Date: August 2, 2017

Exhibit 32-10

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Baltimore Gas and Electric Company for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/S/ DAVID M. VAHOS

David M. Vahos
Senior Vice President, Chief Financial Officer and Treasurer

Date: August 2, 2017

Exhibit 32-11

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Pepco Holdings LLC for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Pepco Holdings LLC.

/S/ DAVID M. VELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

Date: August 2, 2017

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Pepco Holdings LLC for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Pepco Holdings LLC.

/S/ DONNA J. KINZEL

Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer

Date: August 2, 2017

Exhibit 32-13

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Potomac Electric Power Company for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Potomac Electric Power Company.

/S/ DAVID M. VELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

Date: August 2, 2017

Exhibit 32-14

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Potomac Electric Power Company for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Potomac Electric Power Company.

/S/ DONNA J. KINZEL

Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer

Date: August 2, 2017

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Delmarva Power & Light Company for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Delmarva Power & Light Company.

/S/ DAVID M. VELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

Date: August 2, 2017

Exhibit 32-16

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Delmarva Power & Light Company for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Delmarva Power & Light Company.

/S/ DONNA J. KINZEL
Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer

Date: August 2, 2017

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Atlantic City Electric Company for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Atlantic City Electric Company.

/S/ DAVID M. VELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

Date: August 2, 2017

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Atlantic City Electric Company for the quarterly period ended June 30, 2017, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Atlantic City Electric Company.

/S/ DONNA J. KINZEL

Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer

Date: August 2, 2017