

EXELON CORP  
Form 10-Q  
August 09, 2016  
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**UNITED STATES SECURITIES AND EXCHANGE COMMISSION**

**Washington, D.C. 20549**

**FORM 10-Q**

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

**For the Quarterly Period Ended June 30, 2016**

**or**

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

<b>Commission</b>	<b>Name of Registrant; State or Other Jurisdiction of Incorporation; Address of Principal Executive Offices; and Telephone Number</b>	<b>IRS Employer Identification Number</b>
<b>File Number</b>		
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	36-0938600

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000-16844	(312) 394-4321 PECO ENERGY COMPANY (a Pennsylvania corporation)  P.O. Box 8699  2301 Market Street  Philadelphia, Pennsylvania 19101-8699	23-0970240
1-1910	(215) 841-4000 BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation)  2 Center Plaza  110 West Fayette Street  Baltimore, Maryland 21201-3708	52-0280210
001-31403	(410) 234-5000 PEPCO HOLDINGS LLC (a Delaware limited liability company)  701 Ninth Street, N.W.  Washington, District of Columbia 20068	52-2297449
001-01072	(202) 872-2000 POTOMAC ELECTRIC POWER COMPANY (a District of Columbia and Virginia corporation)  701 Ninth Street, N.W.  Washington, District of Columbia 20068	53-0127880
001-01405	(202) 872-2000 DELMARVA POWER & LIGHT COMPANY (a Delaware and Virginia corporation)  500 North Wakefield Drive  Newark, Delaware 19702	51-0084283
001-03559	(202) 872-2000 ATLANTIC CITY ELECTRIC COMPANY (a New Jersey corporation)  500 North Wakefield Drive  Newark, Delaware 19702  (202) 872-2000	21-0398280

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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 or a smaller reporting company. See definition of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

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

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, 2016 was:

Exelon Corporation Common Stock, without par value	922,872,373
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, \$12.50 par value	127,017,042
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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<i>Exelon</i>	Exelon Corporation
<i>Generation</i>	Exelon Generation Company, LLC
<i>ComEd</i>	Commonwealth Edison Company
<i>PECO</i>	PECO Energy Company
<i>BGE</i>	Baltimore Gas and Electric Company
<i>Pepco Holdings or PHI</i>	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
<i>Pepco</i>	Potomac Electric Power Company
<i>Pepco Energy Services or PES</i>	Pepco Energy Services, Inc. and its subsidiaries
<i>PCI</i>	Potomac Capital Investment Corporation and its subsidiaries
<i>DPL</i>	Delmarva Power & Light Company
<i>ACE</i>	Atlantic City Electric Company
<i>ACE Funding or ATF</i>	Atlantic City Electric Transition Funding LLC
<i>BSC</i>	Exelon Business Services Company, LLC
<i>PHISCO</i>	PHI Service Company
<i>Exelon Corporate</i>	Exelon in its corporate capacity as a holding company
<i>PHI Corporate</i>	PHI in its corporate capacity as a holding company
<i>CENG</i>	Constellation Energy Nuclear Group, LLC
<i>Constellation</i>	Constellation Energy Group, Inc.
<i>Antelope Valley</i>	Antelope Valley Solar Ranch One
<i>Exelon Transmission Company</i>	Exelon Transmission Company, LLC
<i>Exelon Wind</i>	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
<i>Ventures</i>	Exelon Ventures Company, LLC
<i>AmerGen</i>	AmerGen Energy Company, LLC
<i>BondCo</i>	RSB BondCo LLC
<i>PEC L.P.</i>	PECO Energy Capital, L.P.
<i>PECO Trust III</i>	PECO Capital Trust III
<i>PECO Trust IV</i>	PECO Energy Capital Trust IV
<i>PETT</i>	PECO Energy Transition Trust
<i>Registrants</i>	Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, collectively
<i>Utility Registrants</i>	ComEd, PECO, BGE, Pepco, DPL and ACE, collectively
<i>Legacy PHI</i>	PHI, Pepco, DPL and ACE, collectively

**Other Terms and Abbreviations**

<i>Note of the Exelon 2015 Form 10-K</i>	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2015 Annual Report on Form 10-K
<i>Note of the PHI 2015 Form 10-K</i>	Reference to specific Note to Consolidated Financial Statements within Legacy PHI's 2015 Annual Report on Form 10-K
<i>1998 restructuring settlement</i>	PECO's 1998 settlement of its restructuring case mandated by the Competition Act
<i>Act 11</i>	Pennsylvania Act 11 of 2012
<i>Act 129</i>	Pennsylvania Act 129 of 2008
<i>AEC</i>	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
<i>AEPS</i>	Pennsylvania Alternative Energy Portfolio Standards
<i>AEPS Act</i>	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
<i>AESO</i>	Alberta Electric Systems Operator

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<i>AFUDC</i>	Allowance for Funds Used During Construction
<i>ALJ</i>	Administrative Law Judge
<i>AMI</i>	Advanced Metering Infrastructure
<i>AMP</i>	Advanced Metering Program
<i>ARC</i>	Asset Retirement Cost
<i>ARO</i>	Asset Retirement Obligation
<i>ARP</i>	Title IV Acid Rain Program
<i>ARRA of 2009</i>	American Recovery and Reinvestment Act of 2009
<i>ASC</i>	Accounting Standards Codification
<i>BGS</i>	Basic Generation Service (the supply of electricity by ACE to retail customers in New Jersey who have not elected to purchase electricity from a competitive supplier)
<i>Block contracts</i>	Forward Purchase Energy Block Contracts
<i>CAIR</i>	Clean Air Interstate Rule
<i>CAISO</i>	California ISO
<i>CAMR</i>	Federal Clean Air Mercury Rule
<i>CERCLA</i>	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
<i>CFL</i>	Compact Fluorescent Light
<i>Clean Air Act</i>	Clean Air Act of 1963, as amended
<i>Clean Water Act</i>	Federal Water Pollution Control Amendments of 1972, as amended
<i>Competition Act</i>	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
<i>Conectiv</i>	Conectiv, LLC, a wholly owned subsidiary of PHI and the parent of DPL and ACE
<i>Conectiv Energy</i>	Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries, which were sold to Calpine in July 2010
<i>Contract EDCs</i>	Pepco, DPL and BGE, the Maryland utilities required by the MDPSC to enter into a contract for new generation
<i>CPI</i>	Consumer Price Index
<i>CPUC</i>	California Public Utilities Commission
<i>CSAPR</i>	Cross-State Air Pollution Rule
<i>CTA</i>	Consolidated tax adjustment
<i>CTC</i>	Competitive Transition Charge
<i>D.C. Circuit Court</i>	United States Court of Appeals for the District of Columbia Circuit
<i>DCPSC</i>	District of Columbia Public Service Commission
<i>DC PLUG</i>	District of Columbia Power Line Undergrounding
<i>Default Electricity Supply</i>	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
<i>Default Electricity Supply Revenue</i>	Revenue primarily from Default Electricity Supply
<i>DOE</i>	United States Department of Energy
<i>DOJ</i>	United States Department of Justice
<i>DPSC</i>	Delaware Public Service Commission
<i>DRP</i>	Direct Stock Purchase and Dividend Reinvestment Plan
<i>DSP</i>	Default Service Provider
<i>DSP Program</i>	Default Service Provider Program



**Table of Contents****GLOSSARY OF TERMS AND ABBREVIATIONS****Other Terms and Abbreviations**

<i>EDCs</i>	Electric distribution companies
<i>EDF</i>	Electricite de France SA and its subsidiaries
<i>EE&amp;C</i>	Energy Efficiency and Conservation/Demand Response
<i>EGS</i>	Electric Generation Supplier
<i>EGTP</i>	ExGen Texas Power, LLC
<i>EIMA</i>	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
<i>EmPower Maryland</i>	A Maryland demand-side management program for Pepco and DPL
<i>EPA</i>	United States Environmental Protection Agency
<i>ERCOT</i>	Electric Reliability Council of Texas
<i>ERISA</i>	Employee Retirement Income Security Act of 1974, as amended
<i>EROA</i>	Expected Rate of Return on Assets
<i>ESPP</i>	Employee Stock Purchase Plan
<i>FASB</i>	Financial Accounting Standards Board
<i>FERC</i>	Federal Energy Regulatory Commission
<i>FRCC</i>	Florida Reliability Coordinating Council
<i>FTC</i>	Federal Trade Commission
<i>GAAP</i>	Generally Accepted Accounting Principles in the United States
<i>GCR</i>	Gas Cost Rate
<i>GHG</i>	Greenhouse Gas
<i>GRT</i>	Gross Receipts Tax
<i>GSA</i>	Generation Supply Adjustment
<i>GWh</i>	Gigawatt hour
<i>HAP</i>	Hazardous air pollutants
<i>Health Care Reform Acts</i>	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
<i>HSR Act</i>	The Hart-Scott-Rodino Antitrust Improvements Act of 1976
<i>IBEW</i>	International Brotherhood of Electrical Workers
<i>ICC</i>	Illinois Commerce Commission
<i>ICE</i>	Intercontinental Exchange
<i>Illinois Act</i>	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
<i>Illinois EPA</i>	Illinois Environmental Protection Agency
<i>Illinois Settlement Legislation</i>	Legislation enacted in 2007 affecting electric utilities in Illinois
<i>Integrus</i>	Integrus Energy Services, Inc.
<i>IPA</i>	Illinois Power Agency
<i>IRC</i>	Internal Revenue Code
<i>IRS</i>	Internal Revenue Service
<i>ISO</i>	Independent System Operator
<i>ISO-NE</i>	ISO New England Inc.
<i>ISO-NY</i>	ISO New York
<i>kV</i>	Kilovolt
<i>kW</i>	Kilowatt
<i>kWh</i>	Kilowatt-hour
<i>LIBOR</i>	London Interbank Offered Rate
<i>LILLO</i>	Lease-In, Lease-Out
<i>LLRW</i>	Low-Level Radioactive Waste
<i>LTIP</i>	Long-Term Incentive Plan
<i>MAPP</i>	Mid-Atlantic Power Pathway
<i>MATS</i>	U.S. EPA Mercury and Air Toxics Rule

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<i>MBR</i>	Market Based Rates Incentive
<i>MDE</i>	Maryland Department of the Environment
<i>MDPSC</i>	Maryland Public Service Commission
<i>MGP</i>	Manufactured Gas Plant
<i>MISO</i>	Midcontinent Independent System Operator, Inc.
<i>mmcf</i>	Million Cubic Feet
<i>Moody's</i>	Moody's Investor Service
<i>MOPR</i>	Minimum Offer Price Rule
<i>MRV</i>	Market-Related Value
<i>MW</i>	Megawatt
<i>MWh</i>	Megawatt hour
<i>NAAQS</i>	National Ambient Air Quality Standards
<i>n.m.</i>	not meaningful
<i>NAV</i>	Net Asset Value
<i>NDT</i>	Nuclear Decommissioning Trust
<i>NEIL</i>	Nuclear Electric Insurance Limited
<i>NERC</i>	North American Electric Reliability Corporation
<i>NGS</i>	Natural Gas Supplier
<i>NJBPU</i>	New Jersey Board of Public Utilities
<i>NJDEP</i>	New Jersey Department of Environmental Protection
<i>Non-Regulatory Agreements Units</i>	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
<i>NOSA</i>	Nuclear Operating Services Agreement
<i>NOV</i>	Notice of Violation
<i>NPDES</i>	National Pollutant Discharge Elimination System
<i>NRC</i>	Nuclear Regulatory Commission
<i>NSPS</i>	New Source Performance Standards
<i>NUGs</i>	Non-utility generators
<i>NWPA</i>	Nuclear Waste Policy Act of 1982
<i>NYMEX</i>	New York Mercantile Exchange
<i>OCI</i>	Other Comprehensive Income
<i>OIESO</i>	Ontario Independent Electricity System Operator
<i>OPC</i>	Office of People's Counsel
<i>OPEB</i>	Other Postretirement Employee Benefits
<i>PA DEP</i>	Pennsylvania Department of Environmental Protection
<i>PAPUC</i>	Pennsylvania Public Utility Commission
<i>PGC</i>	Purchased Gas Cost Clause
<i>PHI Retirement Plan</i>	PHI's noncontributory retirement plan
<i>PJM</i>	PJM Interconnection, LLC
<i>POLR</i>	Provider of Last Resort
<i>POR</i>	Purchase of Receivables
<i>PPA</i>	Power Purchase Agreement
<i>Price-Anderson Act</i>	Price-Anderson Nuclear Industries Indemnity Act of 1957
<i>Preferred Stock</i>	Originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value \$0.01 per share
<i>PRP</i>	Potentially Responsible Parties
<i>PSEG</i>	Public Service Enterprise Group Incorporated
<i>PURTA</i>	Pennsylvania Public Realty Tax Act

**Table of Contents****GLOSSARY OF TERMS AND ABBREVIATIONS****Other Terms and Abbreviations**

<i>PV</i>	Photovoltaic
<i>RCRA</i>	Resource Conservation and Recovery Act of 1976, as amended
<i>REC</i>	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
<i>Regulatory Agreement Units</i>	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
<i>RES</i>	Retail Electric Suppliers
<i>RFP</i>	Request for Proposal
<i>Rider</i>	Reconcilable Surcharge Recovery Mechanism
<i>RGGI</i>	Regional Greenhouse Gas Initiative
<i>RMC</i>	Risk Management Committee
<i>ROE</i>	Return on equity
<i>RPM</i>	PJM Reliability Pricing Model
<i>RPS</i>	Renewable Energy Portfolio Standards
<i>RSSA</i>	Reliability Support Services Agreement
<i>RTEP</i>	Regional Transmission Expansion Plan
<i>RTO</i>	Regional Transmission Organization
<i>S&amp;P</i>	Standard & Poor's Ratings Services
<i>SEC</i>	United States Securities and Exchange Commission
<i>Senate Bill 1</i>	Maryland Senate Bill 1
<i>SERC</i>	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
<i>SERP</i>	Supplemental Employee Retirement Plan
<i>SGIG</i>	Smart Grid Investment Grant from DOE
<i>SGIP</i>	Smart Grid Initiative Program
<i>SILO</i>	Sale-In, Lease-Out
<i>SMPIP</i>	Smart Meter Procurement and Installation Plan
<i>SNF</i>	Spent Nuclear Fuel
<i>SOCAs</i>	Standard Offer Capacity Agreements required to be entered into by ACE pursuant to a New Jersey law enacted to promote the construction of qualified electric generation facilities in New Jersey
<i>SOS</i>	Standard Offer Service
<i>SPP</i>	Southwest Power Pool
<i>Tax Relief Act of 2010</i>	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
<i>Transition Bond Charge</i>	Revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees
<i>Transition Bonds</i>	Transition Bonds issued by ACE Funding
<i>Upstream</i>	Natural gas exploration and production activities
<i>VIE</i>	Variable Interest Entity
<i>WECC</i>	Western Electric Coordinating Council

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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.

**FORWARD-LOOKING STATEMENTS**

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) Exelon's 2015 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 23; (2) PHI's 2015 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 16; (3) this Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors, (b) Part I, 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 18; and (4) 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](http://www.sec.gov) and the Registrants' websites at [www.exeloncorp.com](http://www.exeloncorp.com). Information contained on the Registrants' websites shall not be deemed incorporated into, or to be a part of, this Report.

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**PART I. FINANCIAL INFORMATION**

**Item 1. Financial Statements**

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**Table of Contents****EXELON CORPORATION AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME****(Unaudited)**

<b>(In millions, except per share data)</b>	<b>Three Months Ended</b>		<b>Six Months Ended</b>	
	<b>2016</b>	<b>2015</b>	<b>2016</b>	<b>2015</b>
<b>Operating revenues</b>				
Competitive businesses revenues	\$ 3,234	\$ 4,080	\$ 7,708	\$ 9,714
Rate-regulated utility revenues	3,676	2,434	6,777	5,631
<b>Total operating revenues</b>	<b>6,910</b>	<b>6,514</b>	<b>14,485</b>	<b>15,345</b>
<b>Operating expenses</b>				
Competitive businesses purchased power and fuel	1,576	1,848	4,016	5,274
Rate-regulated utility purchased power and fuel	878	601	1,692	1,645
Operating and maintenance	2,505	2,042	5,341	4,123
Depreciation and amortization	941	602	1,626	1,212
Taxes other than income	394	294	720	598
<b>Total operating expenses</b>	<b>6,294</b>	<b>5,387</b>	<b>13,395</b>	<b>12,852</b>
<b>Gain on sales of assets</b>	<b>31</b>	<b>7</b>	<b>40</b>	<b>8</b>
<b>Operating income</b>	<b>647</b>	<b>1,134</b>	<b>1,130</b>	<b>2,501</b>
<b>Other income and (deductions)</b>				
Interest expense, net	(366)	(145)	(643)	(480)
Interest expense to affiliates	(10)	(10)	(20)	(21)
Other, net	144	(17)	258	64
<b>Total other income and (deductions)</b>	<b>(232)</b>	<b>(172)</b>	<b>(405)</b>	<b>(437)</b>
<b>Income before income taxes</b>	<b>415</b>	<b>962</b>	<b>725</b>	<b>2,064</b>
<b>Income taxes</b>	<b>102</b>	<b>327</b>	<b>285</b>	<b>690</b>
<b>Equity in losses of unconsolidated affiliates</b>	<b>(7)</b>	<b>(2)</b>	<b>(10)</b>	<b>(2)</b>
<b>Net income</b>	<b>306</b>	<b>633</b>	<b>430</b>	<b>1,372</b>
<b>Net income (loss) attributable to noncontrolling interests and preference stock dividends</b>	<b>39</b>	<b>(5)</b>	<b>(10)</b>	<b>41</b>
<b>Net income attributable to common shareholders</b>	<b>\$ 267</b>	<b>\$ 638</b>	<b>\$ 440</b>	<b>\$ 1,331</b>
<b>Comprehensive income, net of income taxes</b>				
Net income	\$ 306	\$ 633	\$ 430	\$ 1,372
<b>Other comprehensive income (loss), net of income taxes</b>				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(12)	(11)	(23)	(23)
Actuarial loss reclassified to periodic benefit cost	46	55	93	110
Pension and non-pension postretirement benefit plan valuation adjustment	(1)		(3)	(29)
Unrealized (loss) gain on cash flow hedges		3	(7)	9

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Unrealized loss on equity investments	(4)		(7)	
Unrealized gain (loss) on foreign currency translation		3	6	(9)
Unrealized gain on marketable securities	2			
Other comprehensive income	31	50	59	58
<b>Comprehensive income</b>	<b>337</b>	<b>683</b>	<b>489</b>	<b>1,430</b>
<b>Comprehensive income (loss) attributable to noncontrolling interests and preference stock dividends</b>	<b>39</b>	<b>(5)</b>	<b>(10)</b>	<b>41</b>
<b>Comprehensive income attributable to common shareholders</b>	<b>\$ 298</b>	<b>\$ 688</b>	<b>\$ 499</b>	<b>\$ 1,389</b>
<b>Average shares of common stock outstanding:</b>				
Basic	924	863	923	862
Diluted	926	866	926	866
<b>Earnings per average common share:</b>				
Basic	\$ 0.29	\$ 0.74	\$ 0.48	\$ 1.54
Diluted	\$ 0.29	\$ 0.74	\$ 0.48	\$ 1.54
<b>Dividends declared per common share</b>	<b>\$ 0.32</b>	<b>\$ 0.31</b>	<b>\$ 0.63</b>	<b>\$ 0.62</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****EXELON CORPORATION AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Six Months Ended</b>	
	<b>2016</b>	<b>June 30, 2015</b>
<b>Cash flows from operating activities</b>		
Net income	\$ 430	\$ 1,372
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	2,396	1,957
Impairment of long-lived assets and losses on regulatory assets	239	24
Gain on sales of assets	(40)	(8)
Deferred income taxes and amortization of investment tax credits	261	211
Net fair value changes related to derivatives	194	(507)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(114)	(2)
Other non-cash operating activities	1,056	579
Changes in assets and liabilities:		
Accounts receivable	86	253
Inventories	89	159
Accounts payable and accrued expenses	(363)	(540)
Option premiums received, net	(10)	22
Collateral received, net	710	659
Income taxes	470	247
Pension and non-pension postretirement benefit contributions	(258)	(301)
Other assets and liabilities	(593)	(156)
Net cash flows provided by operating activities	4,553	3,969
<b>Cash flows from investing activities</b>		
Capital expenditures	(4,489)	(3,460)
Proceeds from nuclear decommissioning trust fund sales	4,977	3,314
Investment in nuclear decommissioning trust funds	(5,094)	(3,437)
Acquisition of businesses, net of cash acquired	(6,642)	(28)
Proceeds from sales of long-lived assets	45	145
Proceeds from termination of direct financing lease investment	360	
Change in restricted cash	15	(3)
Other investing activities	(49)	(77)
Net cash flows used in investing activities	(10,877)	(3,546)
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(798)	94
Proceeds from short-term borrowings with maturities greater than 90 days	194	
Repayments on short-term borrowings with maturities greater than 90 days	(315)	
Issuance of long-term debt	3,174	5,907
Retirement of long-term debt	(217)	(1,708)
Dividends paid on common stock	(582)	(537)
Proceeds from employee stock plans	17	16
Other financing activities	(4)	(59)
Net cash flows provided by financing activities	1,469	3,713



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<b>(Decrease) Increase in cash and cash equivalents</b>	(4,855)	4,136
<b>Cash and cash equivalents at beginning of period</b>	6,502	1,878
<b>Cash and cash equivalents at end of period</b>	\$ 1,647	\$ 6,014

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****EXELON CORPORATION AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	June 30, 2016 (Unaudited)	December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 1,647	\$ 6,502
Restricted cash and cash equivalents	201	205
Accounts receivable, net		
Customer	3,671	3,187
Other	988	912
Mark-to-market derivative assets	759	1,365
Unamortized energy contract assets	69	86
Inventories, net		
Fossil fuel and emission allowances	317	462
Materials and supplies	1,183	1,104
Regulatory assets	1,559	759
Other	1,101	752
<b>Total current assets</b>	<b>11,495</b>	<b>15,334</b>
<b>Property, plant and equipment, net</b>	<b>70,693</b>	<b>57,439</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	10,121	6,065
Nuclear decommissioning trust funds	10,737	10,342
Investments	502	639
Goodwill	6,696	2,672
Mark-to-market derivative assets	546	758
Unamortized energy contract assets	461	484
Pledged assets for Zion Station decommissioning	161	206
Other	1,366	1,445
<b>Total deferred debits and other assets</b>	<b>30,590</b>	<b>22,611</b>
<b>Total assets<sup>(a)</sup></b>	<b>\$ 112,778</b>	<b>\$ 95,384</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****EXELON CORPORATION AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	June 30, 2016 (Unaudited)	December 31, 2015
<b>LIABILITIES AND SHAREHOLDERS EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 951	\$ 533
Long-term debt due within one year	2,693	1,500
Accounts payable	2,826	2,883
Accrued expenses	2,757	2,376
Payables to affiliates	8	8
Regulatory liabilities	503	369
Mark-to-market derivative liabilities	152	205
Unamortized energy contract liabilities	508	100
Renewable energy credit obligation	316	302
PHI merger related obligation	155	
Other	1,025	842
Total current liabilities	11,894	9,118
<b>Long-term debt</b>		
	31,541	23,645
<b>Long-term debt to financing trusts</b>	641	641
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	17,662	13,776
Asset retirement obligations	9,256	8,585
Pension obligations	3,767	3,385
Non-pension postretirement benefit obligations	1,900	1,618
Spent nuclear fuel obligation	1,023	1,021
Regulatory liabilities	4,389	4,201
Mark-to-market derivative liabilities	442	374
Unamortized energy contract liabilities	1,011	117
Payable for Zion Station decommissioning	54	90
Other	1,876	1,491
Total deferred credits and other liabilities	41,380	34,658
Total liabilities <sup>(a)</sup>	85,456	68,062
<b>Commitments and contingencies</b>		
<b>Contingently redeemable noncontrolling interests</b>	24	28
<b>Shareholders equity</b>		
Common stock (No par value, 2000 shares authorized, 923 shares and 920 shares outstanding at June 30, 2016 and December 31, 2015, respectively)	18,722	18,676
Treasury stock, at cost (35 shares at June 30, 2016 and December 31, 2015, respectively)	(2,327)	(2,327)
Retained earnings	11,926	12,068
Accumulated other comprehensive loss, net	(2,565)	(2,624)
Total shareholders equity	25,756	25,793
BGE preference stock not subject to mandatory redemption	193	193

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Noncontrolling interests	1,349	1,308
Total equity	27,298	27,294
<b>Total liabilities and shareholders equity</b>	<b>\$ 112,778</b>	<b>\$ 95,384</b>

(a) Exelon's consolidated assets include \$8,240 million and \$8,268 million at June 30, 2016 and December 31, 2015, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include \$3,461 million and \$3,264 million at June 30, 2016 and December 31, 2015, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 3 Variable Interest Entities.

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**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	Preference Stock	Total Shareholders' Equity
<b>Balance, December 31, 2015</b>	954,668	\$ 18,676	\$ (2,327)	\$ 12,068	\$ (2,624)	\$ 1,308	\$ 193	\$ 27,294
Net income				440		(17)	7	430
Long-term incentive plan activity	2,349	47						47
Employee stock purchase plan issuances	599	17						17
Tax benefit on stock compensation		(18)						(18)
Changes in equity of noncontrolling interests						2		2
Adjustment of contingently redeemable noncontrolling interest due to release of contingency						56		56
Common stock dividends				(582)				(582)
Preference stock dividends							(7)	(7)
Other comprehensive income, net of income taxes					59			59
<b>Balance, June 30, 2016</b>	957,616	\$ 18,722	\$ (2,327)	\$ 11,926	\$ (2,565)	\$ 1,349	\$ 193	\$ 27,298

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
<b>Operating revenues</b>				
Operating revenues	\$ 3,231	\$ 4,079	\$ 7,702	\$ 9,709
Operating revenues from affiliates	358	153	627	365
Total operating revenues	3,589	4,232	8,329	10,074
<b>Operating expenses</b>				
Purchased power and fuel	1,575	1,848	4,015	5,274
Purchased power and fuel from affiliates	2	1	5	8
Operating and maintenance	1,369	1,149	2,665	2,311
Operating and maintenance from affiliates	161	159	332	308
Depreciation and amortization	408	255	697	509
Taxes other than income	118	124	244	246
Total operating expenses	3,633	3,536	7,958	8,656
<b>Gain on sales of assets</b>	31	7	31	6
<b>Operating (loss) income</b>	(13)	703	402	1,424
<b>Other income and (deductions)</b>				
Interest expense, net	(89)	(90)	(176)	(180)
Interest expense to affiliates	(10)	(9)	(20)	(21)
Other, net	117	(31)	210	62
Total other income and (deductions)	18	(130)	14	(139)
<b>Income before income taxes</b>	5	573	416	1,285
<b>Income taxes</b>	(31)	181	120	407
<b>Equity in losses of unconsolidated affiliates</b>	(8)	(2)	(11)	(3)
<b>Net income</b>	28	390	285	875
<b>Net income (loss) attributable to noncontrolling interests</b>	36	(8)	(17)	34
<b>Net (loss) income attributable to membership interest</b>	\$ (8)	\$ 398	\$ 302	\$ 841
<b>Comprehensive income, net of income taxes</b>				
Net income	\$ 28	\$ 390	\$ 285	\$ 875
<b>Other comprehensive income (loss), net of income taxes</b>				
Unrealized gain (loss) on cash flow hedges	1	2	(4)	(3)
Unrealized loss on equity investments	(2)		(4)	
Unrealized gain (loss) on foreign currency translation		3	6	(9)
Unrealized gain on marketable securities	1	1		1

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Other comprehensive income (loss)		6	(2)	(11)
<b>Comprehensive income</b>	28	396	283	864
<b>Comprehensive income (loss) attributable to noncontrolling interests</b>	36	(8)	(17)	34
<b>Comprehensive (loss) income attributable to membership interest</b>	\$ (8)	\$ 404	\$ 300	\$ 830

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

<b>(In millions)</b>	<b>Six Months Ended June 30,</b>	
	<b>2016</b>	<b>2015</b>
<b>Cash flows from operating activities</b>		
Net income	\$ 285	\$ 875
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	1,467	1,255
Impairment of long-lived assets	179	(1)
Gain on sales of assets	(31)	(6)
Deferred income taxes and amortization of investment tax credits	(59)	65
Net fair value changes related to derivatives	199	(396)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(114)	(2)
Other non-cash operating activities	169	134
Changes in assets and liabilities:		
Accounts receivable	123	291
Receivables from and payables to affiliates, net	(77)	(11)
Inventories	57	134
Accounts payable and accrued expenses	(228)	(369)
Option premiums received, net	(10)	22
Collateral received, net	720	682
Income taxes	41	27
Pension and non-pension postretirement benefit contributions	(117)	(122)
Other assets and liabilities	(217)	(155)
<b>Net cash flows provided by operating activities</b>	<b>2,387</b>	<b>2,423</b>
<b>Cash flows from investing activities</b>		
Capital expenditures	(2,051)	(1,764)
Proceeds from nuclear decommissioning trust fund sales	4,977	3,314
Investment in nuclear decommissioning trust funds	(5,094)	(3,437)
Acquisition of businesses	(1)	(28)
Proceeds from sale of long-lived assets	30	144
Change in restricted cash	25	(16)
Other investing activities	(96)	(63)
<b>Net cash flows used in investing activities</b>	<b>(2,210)</b>	<b>(1,850)</b>
<b>Cash flows from financing activities</b>		
Change in short-term borrowings		15
Proceeds from short-term borrowings with maturities greater than 90 days	194	
Repayments of short-term borrowings with maturities greater than 90 days	(15)	
Issuance of long-term debt	173	1,307
Retirement of long-term debt	(131)	(39)
Retirement of long-term debt to affiliate		(550)
Changes in Exelon intercompany money pool	(429)	638
Distribution to member	(111)	(2,262)
Contribution from member	45	
Other financing activities	39	(6)



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Net cash flows used in financing activities	(235)	(897)
<b>Decrease in cash and cash equivalents</b>	<b>(58)</b>	<b>(324)</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>431</b>	<b>780</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 373</b>	<b>\$ 456</b>

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**Table of Contents****EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	June 30, 2016 (Unaudited)	December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 373	\$ 431
Restricted cash and cash equivalents	98	123
Accounts receivable, net		
Customer	2,076	2,095
Other	325	360
Mark-to-market derivative assets	759	1,365
Receivables from affiliates	184	83
Unamortized energy contract assets	69	86
Inventories, net		
Fossil fuel and emission allowances	266	384
Materials and supplies	840	880
Other	735	535
<b>Total current assets</b>	<b>5,725</b>	<b>6,342</b>
<b>Property, plant and equipment, net</b>	<b>26,656</b>	<b>25,843</b>
<b>Deferred debits and other assets</b>		
Nuclear decommissioning trust funds	10,737	10,342
Investments	294	210
Goodwill	47	47
Mark-to-market derivative assets	499	733
Prepaid pension asset	1,673	1,689
Pledged assets for Zion Station decommissioning	161	206
Unamortized energy contract assets	460	484
Deferred income taxes	13	6
Other	632	627
<b>Total deferred debits and other assets</b>	<b>14,516</b>	<b>14,344</b>
<b>Total assets<sup>(a)</sup></b>	<b>\$ 46,897</b>	<b>\$ 46,529</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	June 30, 2016 (Unaudited)	December 31, 2015
<b>LIABILITIES AND EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 208	\$ 29
Long-term debt due within one year	174	90
Accounts payable	1,271	1,583
Accrued expenses	743	935
Payables to affiliates	110	104
Borrowings from Exelon intercompany money pool	817	1,252
Mark-to-market derivative liabilities	134	182
Unamortized energy contract liabilities	75	100
Renewable energy credit obligation	316	302
Other	339	356
<b>Total current liabilities</b>	<b>4,187</b>	<b>4,933</b>
<b>Long-term debt</b>	<b>7,965</b>	<b>7,936</b>
<b>Long-term debt to affiliate</b>	<b>927</b>	<b>933</b>
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	5,750	5,845
Asset retirement obligations	9,081	8,431
Non-pension postretirement benefit obligations	935	924
Spent nuclear fuel obligation	1,023	1,021
Payables to affiliates	2,643	2,577
Mark-to-market derivative liabilities	237	150
Unamortized energy contract liabilities	94	117
Payable for Zion Station decommissioning	54	90
Other	634	602
<b>Total deferred credits and other liabilities</b>	<b>20,451</b>	<b>19,757</b>
<b>Total liabilities<sup>(a)</sup></b>	<b>33,530</b>	<b>33,559</b>
<b>Commitments and contingencies</b>		
<b>Contingently redeemable noncontrolling interests</b>	<b>24</b>	<b>28</b>
<b>Equity</b>		
Member s equity		
Membership interest	9,168	8,997
Undistributed earnings	2,892	2,701
Accumulated other comprehensive loss, net	(65)	(63)
<b>Total member s equity</b>	<b>11,995</b>	<b>11,635</b>
<b>Noncontrolling interests</b>	<b>1,348</b>	<b>1,307</b>
<b>Total equity</b>	<b>13,343</b>	<b>12,942</b>

<b>Total liabilities and equity</b>	\$ 46,897	\$ 46,529
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- (a) Generation s consolidated assets include \$8,172 million and \$8,235 million at June 30, 2016 and December 31, 2015, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation s consolidated liabilities include \$3,211 million and \$3,135 million at June 30, 2016 and December 31, 2015, 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)

(In millions)	Member s Equity				Total Equity
	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	
<b>Balance, December 31, 2015</b>	\$ 8,997	\$ 2,701	\$ (63)	\$ 1,307	\$ 12,942
Net income (loss)		302		(17)	285
Acquisition of noncontrolling interests				2	2
Adjustment of contingently redeemable noncontrolling interests due to release of contingency				56	56
Contribution from member	171				171
Distribution to member		(111)			(111)
Other comprehensive loss, net of income taxes			(2)		(2)
<b>Balance, June 30, 2016</b>	\$ 9,168	\$ 2,892	\$ (65)	\$ 1,348	\$ 13,343

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**COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**

(Unaudited)

(In millions)	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
<b>Operating revenues</b>				
Electric operating revenues	\$ 1,283	\$ 1,147	\$ 2,527	\$ 2,331
Operating revenues from affiliates	3	1	8	2
Total operating revenues	1,286	1,148	2,535	2,333
<b>Operating expenses</b>				
Purchased power	326	269	668	586
Purchased power from affiliate	13	6	18	15
Operating and maintenance	318	337	623	670
Operating and maintenance from affiliate	50	47	113	92
Depreciation and amortization	190	177	379	352
Taxes other than income	65	69	141	146
Total operating expenses	962	905	1,942	1,861
Gain on sale of assets			5	
<b>Operating income</b>	324	243	598	472
<b>Other income and (deductions)</b>				
Interest expense, net	(88)	(78)	(170)	(158)
Interest expense to affiliates	(3)	(3)	(7)	(7)
Other, net	3	5	7	9
Total other income and (deductions)	(88)	(76)	(170)	(156)
<b>Income before income taxes</b>	236	167	428	316
<b>Income taxes</b>	91	68	168	127
<b>Net income</b>	\$ 145	\$ 99	\$ 260	\$ 189
<b>Comprehensive income</b>	\$ 145	\$ 99	\$ 260	\$ 189

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**Table of Contents****COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Six Months Ended June 30,</b>	
	<b>2016</b>	<b>2015</b>
<b>Cash flows from operating activities</b>		
Net income	\$ 260	\$ 189
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	379	352
Deferred income taxes and amortization of investment tax credits	222	36
Other non-cash operating activities	83	222
Changes in assets and liabilities:		
Accounts receivable	(36)	(57)
Receivables from and payables to affiliates, net	1	(10)
Inventories	7	(19)
Accounts payable and accrued expenses	(42)	(53)
Collateral received (posted), net	(10)	
Income taxes	261	239
Pension and non-pension postretirement benefit contributions	(35)	(125)
Other assets and liabilities	38	26
Net cash flows provided by operating activities	1,128	800
<b>Cash flows from investing activities</b>		
Capital expenditures	(1,334)	(1,061)
Other investing activities	21	17
Net cash flows used in investing activities	(1,313)	(1,044)
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(259)	199
Issuance of long-term debt	1,200	400
Retirement of long-term debt		(260)
Contributions from parent	113	45
Dividends paid on common stock	(183)	(150)
Other financing activities	(17)	(5)
Net cash flows provided by financing activities	854	229
<b>Increase (Decrease) in cash and cash equivalents</b>	<b>669</b>	<b>(15)</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>67</b>	<b>66</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 736</b>	<b>\$ 51</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	June 30, 2016 (Unaudited)	December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 736	\$ 67
Restricted cash	2	2
Accounts receivable, net		
Customer	557	533
Other	237	272
Receivables from affiliates	206	199
Inventories, net	155	164
Regulatory assets	213	218
Other	68	63
Total current assets	2,174	1,518
<b>Property, plant and equipment, net</b>		
	18,416	17,502
<b>Deferred debits and other assets</b>		
Regulatory assets	923	895
Investments	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,205	2,172
Prepaid pension asset	1,432	1,490
Other	324	324
Total deferred debits and other assets	7,515	7,512
<b>Total assets</b>	<b>\$ 28,105</b>	<b>\$ 26,532</b>

See the Combined Notes to Consolidated Financial Statements



**Table of Contents****COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	June 30, 2016 (Unaudited)	December 31, 2015
<b>LIABILITIES AND SHAREHOLDERS EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 35	\$ 294
Long-term debt due within one year	665	665
Accounts payable	609	660
Accrued expenses	929	706
Payables to affiliates	65	62
Customer deposits	128	131
Regulatory liabilities	153	155
Mark-to-market derivative liability	18	23
Other	77	70
Total current liabilities	2,679	2,766
<b>Long-term debt</b>		
	7,030	5,844
<b>Long-term debt to financing trust</b>		
	205	205
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	5,142	4,914
Asset retirement obligations	114	111
Non-pension postretirement benefits obligations	249	259
Regulatory liabilities	3,524	3,459
Mark-to-market derivative liability	203	224
Other	521	507
Total deferred credits and other liabilities	9,753	9,474
Total liabilities	19,667	18,289
<b>Commitments and contingencies</b>		
<b>Shareholders equity</b>		
Common stock	1,588	1,588
Other paid-in capital	5,795	5,677
Retained earnings	1,055	978
Total shareholders equity	8,438	8,243
<b>Total liabilities and shareholders equity</b>	<b>\$ 28,105</b>	<b>\$ 26,532</b>

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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
<b>Balance, December 31, 2015</b>	\$ 1,588	\$ 5,677	\$ (1,639)	\$ 2,617	\$ 8,243
Net income			260		260
Appropriation of retained earnings for future dividends			(260)	260	
Common stock dividends				(183)	(183)
Contribution from parent		113			113
Parent tax matter indemnification		5			5
<b>Balance, June 30, 2016</b>	\$ 1,588	\$ 5,795	\$ (1,639)	\$ 2,694	\$ 8,438

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME****(Unaudited)**

(In millions)	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
<b>Operating revenues</b>				
Electric operating revenues	\$ 585	\$ 582	\$ 1,228	\$ 1,259
Natural gas operating revenues	77	79	273	386
Operating revenues from affiliates	2		4	1
<b>Total operating revenues</b>	<b>664</b>	<b>661</b>	<b>1,505</b>	<b>1,646</b>
<b>Operating expenses</b>				
Purchased power	130	161	295	377
Purchased fuel	23	28	100	188
Purchased power from affiliate	64	48	142	110
Operating and maintenance	157	166	333	363
Operating and maintenance from affiliates	33	26	72	51
Depreciation and amortization	67	69	134	131
Taxes other than income	38	39	80	80
<b>Total operating expenses</b>	<b>512</b>	<b>537</b>	<b>1,156</b>	<b>1,300</b>
<b>Gain on sales of assets</b>				<b>1</b>
<b>Operating income</b>	<b>152</b>	<b>124</b>	<b>349</b>	<b>347</b>
<b>Other income and (deductions)</b>				
Interest expense, net	(28)	(25)	(56)	(50)
Interest expense to affiliates	(3)	(3)	(6)	(6)
Other, net	2	1	4	3
<b>Total other income and (deductions)</b>	<b>(29)</b>	<b>(27)</b>	<b>(58)</b>	<b>(53)</b>
<b>Income before income taxes</b>	<b>123</b>	<b>97</b>	<b>291</b>	<b>294</b>
<b>Income taxes</b>	<b>23</b>	<b>27</b>	<b>67</b>	<b>85</b>
<b>Net income attributable to common shareholder</b>	<b>\$ 100</b>	<b>\$ 70</b>	<b>\$ 224</b>	<b>\$ 209</b>
<b>Comprehensive income</b>	<b>\$ 100</b>	<b>\$ 70</b>	<b>\$ 224</b>	<b>\$ 209</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Six Months Ended</b>	
	<b>2016</b>	<b>June 30, 2015</b>
<b>Cash flows from operating activities</b>		
Net income	\$ 224	\$ 209
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	134	131
Deferred income taxes and amortization of investment tax credits	51	4
Other non-cash operating activities	27	45
Changes in assets and liabilities:		
Accounts receivable	(1)	(18)
Receivables from and payables to affiliates, net	(2)	(2)
Inventories	19	21
Accounts payable and accrued expenses	(19)	3
Income taxes	31	57
Pension and non-pension postretirement benefit contributions	(29)	(15)
Other assets and liabilities	(96)	(60)
<b>Net cash flows provided by operating activities</b>	<b>339</b>	<b>375</b>
<b>Cash flows from investing activities</b>		
Capital expenditures	(299)	(289)
Change in restricted cash		(1)
Other investing activities	8	9
<b>Net cash flows used in investing activities</b>	<b>(291)</b>	<b>(281)</b>
<b>Cash flows from financing activities</b>		
Changes in Exelon intercompany money pool		41
Dividends paid on common stock	(139)	(139)
Other financing activities	(1)	
<b>Net cash flows used in financing activities</b>	<b>(140)</b>	<b>(98)</b>
<b>Decrease in cash and cash equivalents</b>	<b>(92)</b>	<b>(4)</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>295</b>	<b>30</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 203</b>	<b>\$ 26</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	June 30, 2016 (Unaudited)	December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 203	\$ 295
Restricted cash and cash equivalents	3	3
Accounts receivable, net		
Customer	248	258
Other	126	146
Receivables from affiliates	5	2
Inventories, net		
Fossil fuel	24	43
Materials and supplies	26	26
Prepaid utility taxes	84	11
Regulatory assets	48	34
Other	34	24
<b>Total current assets</b>	<b>801</b>	<b>842</b>
<b>Property, plant and equipment, net</b>	<b>7,303</b>	<b>7,141</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	1,636	1,583
Investments	26	28
Receivable from affiliates	438	405
Prepaid pension asset	361	347
Other	21	21
<b>Total deferred debits and other assets</b>	<b>2,482</b>	<b>2,384</b>
<b>Total assets</b>	<b>\$ 10,586</b>	<b>\$ 10,367</b>

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**Table of Contents****PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	June 30, 2016 (Unaudited)	December 31, 2015
<b>LIABILITIES AND SHAREHOLDER S EQUITY</b>		
<b>Current liabilities</b>		
Long-term debt due within one year	\$ 300	\$ 300
Accounts payable	269	281
Accrued expenses	100	109
Payables to affiliates	56	55
Customer deposits	60	58
Regulatory liabilities	128	112
Other	39	29
Total current liabilities	952	944
<b>Long-term debt</b>		
Long-term debt to financing trusts	2,281	2,280
Deferred credits and other liabilities	184	184
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	2,920	2,792
Asset retirement obligations	27	27
Non-pension postretirement benefits obligations	288	287
Regulatory liabilities	529	527
Other	84	90
Total deferred credits and other liabilities	3,848	3,723
Total liabilities	7,265	7,131
<b>Commitments and contingencies</b>		
<b>Shareholder s equity</b>		
Common stock	2,455	2,455
Retained earnings	865	780
Accumulated other comprehensive income, net	1	1
Total shareholder s equity	3,321	3,236
<b>Total liabilities and shareholder s equity</b>	<b>\$ 10,586</b>	<b>\$ 10,367</b>

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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
<b>Balance, December 31, 2015</b>	\$ 2,455	\$ 780	\$ 1	\$ 3,236
Net income		224		224
Common stock dividends		(139)		(139)
<b>Balance, June 30, 2016</b>	\$ 2,455	\$ 865	\$ 1	\$ 3,321

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**BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**

(Unaudited)

(In millions)	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
<b>Operating revenues</b>				
Electric operating revenues	\$ 582	\$ 541	\$ 1,260	\$ 1,254
Natural gas operating revenues	94	86	340	402
Operating revenues from affiliates	4	1	9	8
<b>Total operating revenues</b>	<b>680</b>	<b>628</b>	<b>1,609</b>	<b>1,664</b>
<b>Operating expenses</b>				
Purchased power	108	130	235	338
Purchased fuel	20	13	95	155
Purchased power from affiliate	133	96	304	233
Operating and maintenance	177	120	345	276
Operating and maintenance from affiliates	31	29	65	55
Depreciation and amortization	97	87	206	192
Taxes other than income	55	54	114	111
<b>Total operating expenses</b>	<b>621</b>	<b>529</b>	<b>1,364</b>	<b>1,360</b>
<b>Operating income</b>	<b>59</b>	<b>99</b>	<b>245</b>	<b>304</b>
<b>Other income and (deductions)</b>				
Interest expense, net	(20)	(20)	(40)	(42)
Interest expense to affiliates	(4)	(4)	(8)	(8)
Other, net	5	4	11	8
<b>Total other income and (deductions)</b>	<b>(19)</b>	<b>(20)</b>	<b>(37)</b>	<b>(42)</b>
<b>Income before income taxes</b>	<b>40</b>	<b>79</b>	<b>208</b>	<b>262</b>
<b>Income taxes</b>	<b>6</b>	<b>32</b>	<b>73</b>	<b>105</b>
<b>Net income</b>	<b>34</b>	<b>47</b>	<b>135</b>	<b>157</b>
<b>Preference stock dividends</b>	<b>3</b>	<b>3</b>	<b>6</b>	<b>6</b>
<b>Net income attributable to common shareholder</b>	<b>\$ 31</b>	<b>\$ 44</b>	<b>\$ 129</b>	<b>\$ 151</b>
<b>Comprehensive income</b>	<b>\$ 34</b>	<b>\$ 47</b>	<b>\$ 135</b>	<b>\$ 157</b>
<b>Comprehensive income attributable to preference stock dividends</b>	<b>3</b>	<b>3</b>	<b>6</b>	<b>6</b>
<b>Comprehensive income attributable to common shareholder</b>	<b>\$ 31</b>	<b>\$ 44</b>	<b>\$ 129</b>	<b>\$ 151</b>

See the Combined Notes to Consolidated Financial Statements





**Table of Contents****BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Six Months Ended</b>	
	<b>2016</b>	<b>June 30, 2015</b>
<b>Cash flows from operating activities</b>		
Net income	\$ 135	\$ 157
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	206	192
Impairment of long-lived assets and losses on regulatory assets	52	
Deferred income taxes and amortization of investment tax credits	17	54
Other non-cash operating activities	60	76
Changes in assets and liabilities:		
Accounts receivable	11	25
Receivables from and payables to affiliates, net	6	(2)
Inventories	6	23
Accounts payable and accrued expenses	(5)	(59)
Collateral received (posted), net		(23)
Income taxes	46	(6)
Pension and non-pension postretirement benefit contributions	(42)	(9)
Other assets and liabilities	(3)	61
<b>Net cash flows provided by operating activities</b>	<b>489</b>	<b>489</b>
<b>Cash flows from investing activities</b>		
Capital expenditures	(392)	(304)
Change in restricted cash	5	21
Other investing activities	12	8
<b>Net cash flows used in investing activities</b>	<b>(375)</b>	<b>(275)</b>
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(2)	(120)
Retirement of long-term debt	(39)	(37)
Dividends paid on preference stock	(6)	(6)
Dividends paid on common stock	(90)	(77)
Contributions from parent	21	
Other financing activities	(2)	(14)
<b>Net cash flows used in financing activities</b>	<b>(118)</b>	<b>(254)</b>
<b>Decrease in cash and cash equivalents</b>	<b>(4)</b>	<b>(40)</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>9</b>	<b>64</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 5</b>	<b>\$ 24</b>

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**Table of Contents****BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	June 30, 2016 (Unaudited)	December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 5	\$ 9
Restricted cash and cash equivalents	19	24
Accounts receivable, net		
Customer	289	300
Other	70	112
Inventories, net		
Gas held in storage	22	36
Materials and supplies	41	33
Prepaid utility taxes		61
Regulatory assets	261	267
Other	7	3
Total current assets	714	845
<b>Property, plant and equipment, net</b>	<b>6,747</b>	<b>6,597</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	520	514
Investments	12	12
Prepaid pension asset	323	319
Other	9	8
Total deferred debits and other assets	864	853
<b>Total assets<sup>(a)</sup></b>	<b>\$ 8,325</b>	<b>\$ 8,295</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	June 30, 2016 (Unaudited)	December 31, 2015
<b>LIABILITIES AND SHAREHOLDERS EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 208	\$ 210
Long-term debt due within one year	380	378
Accounts payable	222	209
Accrued expenses	101	110
Payables to affiliates	58	52
Customer deposits	106	102
Regulatory liabilities	60	38
Other	30	35
<b>Total current liabilities</b>	<b>1,165</b>	<b>1,134</b>
<b>Long-term debt</b>	<b>1,440</b>	<b>1,480</b>
<b>Long-term debt to financing trust</b>	<b>252</b>	<b>252</b>
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	2,111	2,081
Asset retirement obligations	15	17
Non-pension postretirement benefits obligations	204	209
Regulatory liabilities	137	184
Other	71	61
<b>Total deferred credits and other liabilities</b>	<b>2,538</b>	<b>2,552</b>
<b>Total liabilities<sup>(a)</sup></b>	<b>5,395</b>	<b>5,418</b>
<b>Commitments and contingencies</b>		
<b>Shareholders equity</b>		
Common stock	1,381	1,367
Retained earnings	1,359	1,320
<b>Total shareholders equity</b>	<b>2,740</b>	<b>2,687</b>
Preference stock not subject to mandatory redemption	190	190
<b>Total equity</b>	<b>2,930</b>	<b>2,877</b>
<b>Total liabilities and shareholders equity</b>	<b>\$ 8,325</b>	<b>\$ 8,295</b>

(a) BGE's consolidated assets include \$20 million and \$26 million at June 30, 2016 and December 31, 2015, respectively, of BGE's consolidated VIE that can only be used to settle the liabilities of the VIE. BGE's consolidated liabilities include \$82 million and \$122 million at June 30, 2016 and December 31, 2015, respectively, of BGE's consolidated VIE for which the VIE creditors do not have recourse to BGE. See Note

3 Variable Interest Entities.

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**Table of Contents****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	Preference Stock Not Subject To Mandatory Redemption	Total Equity
<b>Balance, December 31, 2015</b>	\$ 1,367	\$ 1,320	\$ 2,687	\$ 190	\$ 2,877
Net income		135	135		135
Preference stock dividends		(6)	(6)		(6)
Common stock dividends		(90)	(90)		(90)
Distribution to parent	(7)		(7)		(7)
Contribution from parent	21		21		21
<b>Balance, June 30, 2016</b>	\$ 1,381	\$ 1,359	\$ 2,740	\$ 190	\$ 2,930

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**Table of Contents****PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME****(Unaudited)**

<b>(In millions)</b>	<i>Successor</i> <b>Three Months</b> <b>Ended June 30,</b> <b>2016</b>	<i>Predecessor</i> <b>Three Months</b> <b>Ended June 30,</b> <b>2015</b>	<i>Successor</i> <b>March 24 to</b> <b>June 30,</b> <b>2016</b>	<i>Predecessor</i> <b>January 1 to Six Months</b> <b>March 23, Ended June 30,</b> <b>2016 2015</b>	
<b>Operating revenues</b>					
Electric operating revenues	\$ 1,030	\$ 1,094	\$ 1,120	\$ 1,096	\$ 2,362
Natural gas operating revenues	26	25	28	57	111
Operating revenues from affiliates	10		23		
<b>Total operating revenues</b>	<b>1,066</b>	<b>1,119</b>	<b>1,171</b>	<b>1,153</b>	<b>2,473</b>
<b>Operating expenses</b>					
Purchased power	263	417	288	471	1,005
Purchased fuel	9	12	11	26	62
Purchased power and fuel from affiliates	144		155		
Operating and maintenance	223	288	670	294	589
Operating and maintenance from affiliates	23		25		
Depreciation, amortization and accretion	160	152	174	152	307
Taxes other than income	108	111	123	105	229
<b>Total operating expenses</b>	<b>930</b>	<b>980</b>	<b>1,446</b>	<b>1,048</b>	<b>2,192</b>
<b>Operating income (loss)</b>	<b>136</b>	<b>139</b>	<b>(275)</b>	<b>105</b>	<b>281</b>
<b>Other income and (deductions)</b>					
Interest expense, net	(66)	(71)	(71)	(65)	(140)
Other, net	11	12	12	(4)	21
<b>Total other income and (deductions)</b>	<b>(55)</b>	<b>(59)</b>	<b>(59)</b>	<b>(69)</b>	<b>(119)</b>
<b>Income (loss) before income taxes</b>	<b>81</b>	<b>80</b>	<b>(334)</b>	<b>36</b>	<b>162</b>
<b>Income taxes</b>	<b>29</b>	<b>27</b>	<b>(77)</b>	<b>17</b>	<b>56</b>
<b>Net income (loss) attributable to membership interest/common shareholders</b>	<b>\$ 52</b>	<b>\$ 53</b>	<b>\$ (257)</b>	<b>\$ 19</b>	<b>\$ 106</b>
<b>Comprehensive income (loss), net of income taxes</b>					
Net income (loss)	\$ 52	\$ 53	\$ (257)	\$ 19	\$ 106
<b>Other comprehensive income, net of income taxes</b>					
Pension and non-pension postretirement benefit plans:					
Actuarial loss reclassified to periodic cost		3		1	4
Other comprehensive income		3		1	4
<b>Comprehensive income (loss)</b>	<b>\$ 52</b>	<b>\$ 56</b>	<b>\$ (257)</b>	<b>\$ 20</b>	<b>\$ 110</b>

See the Combined Notes to Consolidated Financial Statements





**Table of Contents****PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<i>Successor</i> <b>March 24 to June 30, 2016</b>	<i>Predecessor</i> <b>January 1 to March 23, 2016</b>	<i>Predecessor</i> <b>Six Months Ended June 30, 2015</b>
<b>Cash flows from operating activities</b>			
Net (loss) income	\$ (257)	\$ 19	\$ 106
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	174	152	307
Deferred income taxes and amortization of investment tax credits	(16)	19	73
Net fair value changes related to derivatives		18	
Other non-cash operating activities	444	46	101
Changes in assets and liabilities:			
Accounts receivable	56	(28)	(196)
Receivables from and payables to affiliates, net	39		
Inventories		(4)	
Accounts payable and accrued expenses	(35)	42	19
Collateral received, net		1	
Income taxes	22	12	
Pension and non-pension postretirement benefit contributions	(2)	(4)	(8)
Other assets and liabilities	(237)	(9)	(63)
<b>Net cash flows provided by operating activities</b>	<b>188</b>	<b>264</b>	<b>339</b>
<b>Cash flows from investing activities</b>			
Capital expenditures	(339)	(273)	(562)
Proceeds from sales of long-lived assets	15		
Changes in restricted cash	(34)	3	11
Purchases of investments		(68)	
Other investing activities	8	(5)	(2)
<b>Net cash flows used in investing activities</b>	<b>(350)</b>	<b>(343)</b>	<b>(553)</b>
<b>Cash flows from financing activities</b>			
Changes in short-term borrowings	(537)	(121)	69
Proceeds from short-term borrowings with maturities greater than 90 days		500	
Repayments of short-term borrowings with maturities greater than 90 days	(300)		
Issuance of long-term debt	1		408
Retirement of long-term debt	(16)	(11)	(138)
Issuance of preferred stock			36
Dividends paid on common stock			(137)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan and employee-related compensation		2	19
Distribution to member	(124)		
Contribution from member	1,088		
Change in Exelon intercompany money pool	28		
Other financing activities	(3)	2	(24)

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Net cash flows provided by financing activities	137	372	233
<b>(Decrease) Increase in cash and cash equivalents</b>	<b>(25)</b>	<b>293</b>	<b>19</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>319</b>	<b>26</b>	<b>15</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 294</b>	<b>\$ 319</b>	<b>\$ 34</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	<i>Successor</i> <b>June 30, 2016</b> <i>(Unaudited)</i>	<i>Predecessor</i> <b>December 31, 2015</b>
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 294	\$ 26
Restricted cash and cash equivalents	44	14
Accounts receivable, net		
Customer	501	581
Other	237	319
Mark-to-market derivative asset		18
Inventories, net		
Gas held in storage	5	9
Materials and supplies	121	122
Regulatory assets	730	305
Other	87	80
Total current assets	2,019	1,474
<b>Property, plant and equipment, net</b>	<b>11,148</b>	<b>10,864</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	3,044	2,277
Investments	131	80
Goodwill	4,024	1,406
Long-term note receivable	4	4
Prepaid pension asset	489	
Deferred income taxes	5	14
Other	57	69
Total deferred debits and other assets	7,754	3,850
<b>Total assets<sup>(a)</sup></b>	<b>\$ 20,921</b>	<b>\$ 16,188</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

<b>(In millions)</b>	<b>Successor June 30, 2016 (Unaudited)</b>	<b>Predecessor December 31, 2015</b>
<b>LIABILITIES AND EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 500	\$ 958
Long-term debt due within one year	551	456
Accounts payable	344	404
Accrued expenses	306	266
Payables to affiliates	90	
Unamortized energy contract liabilities	433	
Borrowings from Exelon intercompany money pool	34	
Customer deposits	128	107
Merger related obligation	118	
Regulatory liabilities	101	66
Other	31	70
Total current liabilities	2,636	2,327
<b>Long-term debt</b>		
	5,522	4,823
<b>Deferred credits and other liabilities</b>		
Regulatory liabilities	171	147
Deferred income taxes and unamortized investment tax credits	3,470	3,406
Asset retirement obligations	12	8
Pension obligations		466
Non-pension postretirement benefit obligations	141	215
Unamortized energy contract liabilities	918	
Other	280	200
Total deferred credits and other liabilities	4,992	4,442
Total liabilities <sup>(a)</sup>	13,150	11,592
<b>Commitments and contingencies</b>		
<b>Preferred stock<sup>(b)</sup></b>		183
<b>Member s equity/Shareholders equity</b>		
Membership interest/Common stock <sup>(c)</sup>	8,028	3,832
Undistributed (losses)/Retained earnings	(257)	617
Accumulated other comprehensive loss, net		(36)
Total member s equity/shareholders equity	7,771	4,413
<b>Total liabilities and member s equity/shareholders equity</b>	<b>\$ 20,921</b>	<b>\$ 16,188</b>

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- (a) PHI's consolidated total assets include \$45 million and \$30 million at June 30, 2016 and December 31, 2015, respectively, of PHI's consolidated VIE that can only be used to settle the liabilities of the VIE. PHI's consolidated total liabilities include \$166 million and \$172 million at June 30, 2016 and December 31, 2015, respectively, of PHI's consolidated VIE for which the VIE creditors do not have recourse to PHI. See Note 3 Variable Interest Entities.
- (b) At December 31, 2015, PHI had 18,000 shares of Series A preferred stock outstanding, par value \$0.01 per share.
- (c) At December 31, 2015, PHI's (predecessor) shareholders' equity included \$3,829 million of other paid-in capital and \$3 million of common stock. At December 31, 2015, PHI had 400,000,000 shares of common stock authorized and 254,289,261 shares of common stock outstanding, par value \$0.01 per share.

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## PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

## CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(Unaudited)

(In millions)	Common Stock/ Membership Interest <sup>(a)</sup>	Retained Earnings/ Undistributed Losses	Accumulated Other Comprehensive Loss, net	Total Shareholders / Members Equity
<i>Predecessor</i>				
<b>Balance at December 31, 2015</b>	\$ 3,832	\$ 617	\$ (36)	\$ 4,413
Net income		19		19
Original issue shares, net	3			3
Net activity related to stock-based awards	3			3
Other comprehensive income, net of income taxes			1	1
<b>Balance at March 23, 2016</b>	\$ 3,838	\$ 636	\$ (35)	\$ 4,439
<i>Successor</i>				
<b>Balance at March 24, 2016<sup>(b)</sup></b>	\$ 7,200	\$	\$	\$ 7,200
Net loss		(257)		(257)
Distribution to member <sup>(c)</sup>	(251)			(251)
Contribution from member	1,088			1,088
Distribution of net retirement benefit obligation to member	53			53
Assumption of member liabilities <sup>(d)</sup>	(62)			(62)
<b>Balance at June 30, 2016</b>	\$ 8,028	\$ (257)	\$	\$ 7,771

(a) At March 23, 2016 and December 31, 2015, PHI's (predecessor) shareholders' equity included \$3,835 million and \$3,829 million of other paid-in capital, and \$3 million and \$3 million of common stock, respectively.

(b) The March 24, 2016, beginning balance differs from the PHI Merger total purchase price by \$59 million related to an acquisition accounting adjustment recorded at Exelon Corporate to reflect unitary state income tax consequences of the merger.

(c) Distribution to member includes \$235 million of net assets associated with PHI's unregulated business interests and \$16 million of cash, each of which were distributed by PHI to Exelon.

(d) The liabilities assumed include \$29 million for PHI stock-based compensation awards and \$33 million for a merger related obligation, each assumed by PHI from Exelon. See Note 4 Mergers, Acquisitions and Dispositions.

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**POTOMAC ELECTRIC POWER COMPANY**  
**STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**

(Unaudited)

(In millions)	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
<b>Operating revenues</b>				
Electric operating revenues	\$ 508	\$ 503	\$ 1,058	\$ 1,047
Operating revenues from affiliates	1	1	3	2
Total operating revenues	509	504	1,061	1,049
<b>Operating expenses</b>				
Purchased power	64	162	256	373
Purchased power from affiliates	88		95	
Operating and maintenance	100	102	389	213
Operating and maintenance from affiliates	9	1	10	2
Depreciation and amortization	70	63	144	125
Taxes other than income	89	93	182	190
Total operating expenses	420	421	1,076	903
<b>Gain on sale of assets</b>	8		8	
<b>Operating income (loss)</b>	97	83	(7)	146
<b>Other income and (deductions)</b>				
Interest expense, net	(31)	(31)	(68)	(61)
Other, net	6	8	14	13
Total other income and (deductions)	(25)	(23)	(54)	(48)
<b>Income (loss) before income taxes</b>	72	60	(61)	98
<b>Income taxes</b>	23	18	(1)	30
<b>Net income (loss) attributable to common shareholder</b>	\$ 49	\$ 42	\$ (60)	\$ 68
<b>Comprehensive income (loss)</b>	\$ 49	\$ 42	\$ (60)	\$ 68

See the Combined Notes to Consolidated Financial Statements



**Table of Contents****POTOMAC ELECTRIC POWER COMPANY****STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Six Months Ended</b>	
	<b>2016</b>	<b>June 30, 2015</b>
<b>Cash flows from operating activities</b>		
Net (loss) income	\$ (60)	\$ 68
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:		
Depreciation and amortization	144	125
Deferred income taxes and amortization of investment tax credits	20	31
Other non-cash operating activities	158	33
Changes in assets and liabilities:		
Accounts receivable	(41)	(99)
Receivables from and payables to affiliates, net	47	2
Inventories	1	(4)
Accounts payable and accrued expenses	(19)	(9)
Income taxes	165	
Pension and non-pension postretirement benefit contributions	(3)	(6)
Other assets and liabilities	(47)	(36)
<b>Net cash flows provided by operating activities</b>	<b>365</b>	<b>105</b>
<b>Cash flows from investing activities</b>		
Capital expenditures	(256)	(254)
Proceeds from sale of long-lived asset	12	
Purchases of investments	(31)	
Changes in restricted cash	(31)	3
Other investing activities	(1)	3
<b>Net cash flows used in investing activities</b>	<b>(307)</b>	<b>(248)</b>
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(64)	(104)
Issuance of long-term debt	1	208
Retirement of long-term debt	(5)	(17)
Dividends paid on common stock	(55)	(31)
Contribution from parent	187	112
Other financing activities		(9)
<b>Net cash flows provided by financing activities</b>	<b>64</b>	<b>159</b>
<b>Increase in cash and cash equivalents</b>	<b>122</b>	<b>16</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>5</b>	<b>6</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 127</b>	<b>\$ 22</b>

See the Combined Notes to Consolidated Financial Statements



**Table of Contents****POTOMAC ELECTRIC POWER COMPANY****BALANCE SHEETS****(Unaudited)**

(In millions)	June 30, 2016 (Unaudited)	December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 127	\$ 5
Restricted cash and cash equivalents	33	2
Accounts receivable, net		
Customer	255	230
Other	116	261
Inventories, net	65	67
Regulatory assets	129	140
Other	9	21
<b>Total current assets</b>	<b>734</b>	<b>726</b>
<b>Property, plant and equipment, net</b>	<b>5,321</b>	<b>5,162</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	669	661
Investments	99	68
Prepaid pension asset	272	287
Other	4	4
<b>Total deferred debits and other assets</b>	<b>1,044</b>	<b>1,020</b>
<b>Total assets</b>	<b>\$ 7,099</b>	<b>\$ 6,908</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****POTOMAC ELECTRIC POWER COMPANY****BALANCE SHEETS****(Unaudited)**

(In millions)	June 30, 2016 (Unaudited)	December 31, 2015
<b>LIABILITIES AND SHAREHOLDER S EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$	\$ 64
Long-term debt due within one year	12	11
Accounts payable	127	145
Accrued expenses	141	119
Payables to affiliates	77	30
Customer deposits	54	46
Regulatory liabilities	27	15
Merger related obligation	42	
Other	13	25
Total current liabilities	493	455
<b>Long-term debt</b>		
	2,337	2,340
<b>Deferred credits and other liabilities</b>		
Regulatory liabilities	24	29
Deferred income taxes and unamortized investment tax credits	1,755	1,723
Non-pension postretirement benefit obligations	48	49
Other	163	72
Total deferred credits and other liabilities	1,990	1,873
Total liabilities	4,820	4,668
<b>Commitments and contingencies</b>		
<b>Shareholder s equity</b>		
Common stock	1,309	1,122
Retained earnings	970	1,118
Total shareholder s equity	2,279	2,240
<b>Total liabilities and shareholder s equity</b>	<b>\$ 7,099</b>	<b>\$ 6,908</b>

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**POTOMAC ELECTRIC POWER COMPANY**  
**STATEMENT OF CHANGES IN SHAREHOLDER S EQUITY**

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholder s Equity
<b>Balance, December 31, 2015</b>	\$ 1,122	\$ 1,118	\$ 2,240
Net loss		(60)	(60)
Common stock dividends		(88)	(88)
Contribution from parent	187		187
<b>Balance, June 30, 2016</b>	\$ 1,309	\$ 970	\$ 2,279

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****DELMARVA POWER & LIGHT COMPANY****STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME****(Unaudited)**

(In millions)	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
<b>Operating revenues</b>				
Electric operating revenues	\$ 253	\$ 244	\$ 554	\$ 577
Natural gas operating revenues	26	25	85	111
Operating revenues from affiliates	2	2	4	3
<b>Total operating revenues</b>	<b>281</b>	<b>271</b>	<b>643</b>	<b>691</b>
<b>Operating expenses</b>				
Purchased power	70	114	216	292
Purchased fuel	9	11	35	58
Purchased power from affiliate	43		47	
Operating and maintenance	73	74	277	156
Operating and maintenance from affiliates	5	1	6	1
Depreciation, amortization and accretion	38	35	76	74
Taxes other than income	13	12	28	24
<b>Total operating expenses</b>	<b>251</b>	<b>247</b>	<b>685</b>	<b>605</b>
<b>Operating income (loss)</b>	<b>30</b>	<b>24</b>	<b>(42)</b>	<b>86</b>
<b>Other income and (deductions)</b>				
Interest expense, net	(13)	(13)	(25)	(25)
Other, net	3	2	6	5
<b>Total other income and (deductions)</b>	<b>(10)</b>	<b>(11)</b>	<b>(19)</b>	<b>(20)</b>
<b>Income (loss) before income taxes</b>	<b>20</b>	<b>13</b>	<b>(61)</b>	<b>66</b>
<b>Income taxes</b>	<b>8</b>	<b>5</b>	<b>(1)</b>	<b>26</b>
<b>Net income (loss) attributable to common shareholder</b>	<b>\$ 12</b>	<b>\$ 8</b>	<b>\$ (60)</b>	<b>\$ 40</b>
<b>Comprehensive income (loss)</b>	<b>\$ 12</b>	<b>\$ 8</b>	<b>\$ (60)</b>	<b>\$ 40</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****DELMARVA POWER & LIGHT COMPANY****STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Six Months Ended June 30,</b>	
	<b>2016</b>	<b>2015</b>
<b>Cash flows from operating activities</b>		
Net (loss) income	\$ (60)	\$ 40
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	76	74
Deferred income taxes and amortization of investment tax credits	23	26
Other non-cash operating activities	121	22
Changes in assets and liabilities:		
Accounts receivable	30	(43)
Receivables from and payables to affiliates, net	15	3
Inventories	1	6
Accounts payable and accrued expenses	(2)	(9)
Collateral received	1	
Income taxes	66	
Other assets and liabilities	(51)	(4)
<b>Net cash flows provided by operating activities</b>	<b>220</b>	<b>115</b>
<b>Cash flows from investing activities</b>		
Capital expenditures	(182)	(154)
Changes in restricted cash	(1)	5
Other investing activities	3	1
<b>Net cash flows used in investing activities</b>	<b>(180)</b>	<b>(148)</b>
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(105)	(76)
Issuance of long-term debt		200
Retirement of long-term debt		(100)
Dividends paid on common stock	(38)	(62)
Contribution from parent	113	75
Other financing activities		(2)
<b>Net cash flows (used in) provided by financing activities</b>	<b>(30)</b>	<b>35</b>
<b>Increase in cash and cash equivalents</b>	<b>10</b>	<b>2</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>5</b>	<b>4</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 15</b>	<b>\$ 6</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****DELMARVA POWER & LIGHT COMPANY****BALANCE SHEETS****(Unaudited)**

(In millions)	June 30, 2016 (Unaudited)	December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 15	\$ 5
Restricted cash and cash equivalents	1	
Accounts receivable, net		
Customer	124	154
Other	32	96
Inventories, net		
Gas held in storage	5	8
Materials and supplies	33	32
Renewable energy credits	16	9
Regulatory assets	63	72
Other	1	12
Total current assets	290	388
<b>Property, plant and equipment, net</b>	<b>3,177</b>	<b>3,070</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	295	299
Goodwill	8	8
Prepaid pension asset	193	202
Other	8	2
Total deferred debits and other assets	504	511
<b>Total assets</b>	<b>\$ 3,971</b>	<b>\$ 3,969</b>

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**Table of Contents****DELMARVA POWER & LIGHT COMPANY****BALANCE SHEETS****(Unaudited)**

(In millions)	June 30, 2016 (Unaudited)	December 31, 2015
<b>LIABILITIES AND SHAREHOLDER S EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$	\$ 105
Long-term debt due within one year	218	204
Accounts payable	93	109
Accrued expenses	45	31
Payables to affiliates	37	20
Customer deposits	38	31
Regulatory liabilities	53	49
Merger related obligation	27	
Other	7	15
Total current liabilities	518	564
<b>Long-term debt</b>		
	1,047	1,061
<b>Deferred credits and other liabilities</b>		
Regulatory liabilities	102	111
Deferred income taxes and unamortized investment tax credits	968	945
Non-pension postretirement benefit obligations	20	19
Other	64	32
Total deferred credits and other liabilities	1,154	1,107
Total liabilities	2,719	2,732
<b>Commitments and contingencies</b>		
<b>Shareholder s equity</b>		
Common stock	725	612
Retained earnings	527	625
Total shareholder s equity	1,252	1,237
<b>Total liabilities and shareholder s equity</b>	<b>\$ 3,971</b>	<b>\$ 3,969</b>

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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
<b>Balance, December 31, 2015</b>	\$ 612	\$ 625	\$ 1,237
Net loss		(60)	(60)
Common stock dividends		(38)	(38)
Contribution from parent	113		113
<b>Balance, June 30, 2016</b>	\$ 725	\$ 527	\$ 1,252

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**ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY**  
**CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**

(Unaudited)

(In millions)	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
<b>Operating revenues</b>				
Electric operating revenues	\$ 269	\$ 284	\$ 559	\$ 616
Operating revenues from affiliates	1	1	2	2
Total operating revenues	270	285	561	618
<b>Operating expenses</b>				
Purchased power	129	147	285	338
Purchased power from affiliates	12		13	
Operating and maintenance	63	68	275	136
Operating and maintenance from affiliates	5	1	5	2
Depreciation, amortization and accretion	41	43	81	86
Taxes other than income	2	1	4	3
Total operating expenses	252	260	663	565
<b>Gain on sale of assets</b>	1		1	
<b>Operating income (loss)</b>	19	25	(101)	53
<b>Other income and (deductions)</b>				
Interest expense, net	(16)	(16)	(32)	(32)
Other, net	2	1	5	3
Total other income and (deductions)	(14)	(15)	(27)	(29)
<b>Income (loss) before income taxes</b>	5	10	(128)	24
<b>Income taxes</b>	2	4	(31)	9
<b>Net income (loss) attributable to common shareholder</b>	\$ 3	\$ 6	\$ (97)	\$ 15
<b>Comprehensive income (loss)</b>	\$ 3	\$ 6	\$ (97)	\$ 15

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**Table of Contents****ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Six Months Ended</b>	
	<b>2016</b>	<b>June 30, 2015</b>
<b>Cash flows from operating activities</b>		
Net (loss) income	\$ (97)	\$ 15
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	81	86
Deferred income taxes and amortization of investment tax credits	(28)	9
Other non-cash operating activities	138	17
Changes in assets and liabilities:		
Accounts receivable	31	(55)
Receivables from and payables to affiliates, net	8	
Inventories	(2)	(1)
Accounts payable and accrued expenses	6	37
Income taxes	181	(1)
Other assets and liabilities	(110)	(24)
Net cash flows provided by operating activities	208	83
<b>Cash flows from investing activities</b>		
Capital expenditures	(164)	(138)
Proceeds from sale of long-lived asset	2	
Changes in restricted cash	1	
Other investing activities	1	(2)
Net cash flows used in investing activities	(160)	(140)
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(5)	91
Retirement of long-term debt	(22)	(21)
Dividends paid on common stock	(11)	(12)
Contribution from parent	139	
Other financing activities	(1)	
Net cash flows provided by financing activities	100	58
<b>Increase in cash and cash equivalents</b>	148	1
<b>Cash and cash equivalents at beginning of period</b>	3	2
<b>Cash and cash equivalents at end of period</b>	\$ 151	\$ 3

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**Table of Contents****ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	June 30, 2016 (Unaudited)	December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 151	\$ 3
Restricted cash and cash equivalents	10	12
Accounts receivable, net		
Customer	122	156
Other	69	242
Receivables from affiliates	1	
Inventories, net	23	23
Prepaid utility taxes	36	
Regulatory assets	97	98
Other	4	12
<b>Total current assets</b>	<b>513</b>	<b>546</b>
<b>Property, plant and equipment, net</b>	<b>2,427</b>	<b>2,322</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	418	414
Long-term note receivable	4	4
Prepaid pension asset	76	82
Other	23	19
<b>Total deferred debits and other assets</b>	<b>521</b>	<b>519</b>
<b>Total assets<sup>(a)</sup></b>	<b>\$ 3,461</b>	<b>\$ 3,387</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	June 30, 2016 (Unaudited)	December 31, 2015
<b>LIABILITIES AND SHAREHOLDER S EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$	\$ 5
Long-term debt due within one year	44	48
Accounts payable	107	96
Accrued expenses	86	70
Payables to affiliates	25	16
Customer deposits	37	30
Regulatory liabilities	21	18
Merger related obligation	48	
Other	7	14
Total current liabilities	375	297
<b>Long-term debt</b>		
	1,136	1,153
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	859	885
Non-pension postretirement benefit obligations	35	33
Regulatory liabilities	2	7
Other	23	12
Total deferred credits and other liabilities	919	937
Total liabilities <sup>(a)</sup>	2,430	2,387
<b>Commitments and contingencies</b>		
<b>Shareholder s equity</b>		
Common stock	912	773
Retained earnings	119	227
Total shareholder s equity	1,031	1,000
<b>Total liabilities and shareholder s equity</b>	<b>\$ 3,461</b>	<b>\$ 3,387</b>

(a) ACE s consolidated total assets include \$29 million and \$30 million at June 30, 2016 and December 31, 2015, respectively, of ACE s consolidated VIE that can only be used to settle the liabilities of the VIE. ACE s consolidated total liabilities include \$150 million and \$172 million at June 30, 2016 and December 31, 2015, respectively, of ACE s consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 3 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements



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**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
<b>Balance, December 31, 2015</b>	\$ 773	\$ 227	\$ 1,000
Net loss		(97)	(97)
Common stock dividends		(11)	(11)
Contribution from parent	139		139
<b>Balance, June 30, 2016</b>	\$ 912	\$ 119	\$ 1,031

See the Combined Notes to Consolidated Financial Statements



**Table of Contents****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**

<b>Registrant</b>	<b>1</b>	<b>2</b>	<b>3</b>	<b>4</b>	<b>5</b>	<b>6</b>	<b>7</b>	<b>8</b>	<b>9</b>	<b>10</b>	<b>11</b>	<b>12</b>	<b>13</b>	<b>14</b>	<b>15</b>	<b>16</b>	<b>17</b>	<b>18</b>	<b>19</b>	<b>20</b>	
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. Significant Accounting Policies (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.

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

*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)**

Pursuant to 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 the 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 that had solely related to PHI, Pepco, DPL or ACE activities now also apply to Exelon, unless otherwise noted. When appropriate, Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE are named specifically for their related activities and disclosures.

Certain prior year amounts in the Consolidated Statements of Operations and Comprehensive Income, Consolidated Balance Sheets and Consolidated Statements of Cash Flows of PHI, Pepco, DPL and ACE have been reclassified to conform the presentation of these amounts to the current period presentation in Exelon's financial statements. Most significantly for PHI, Pepco, DPL and ACE, current regulatory assets and liabilities have been presented separately from the non-current portions in each respective Consolidated Balance Sheet where recovery or refund is expected within the next 12 months. Additionally, for PHI, Pepco, DPL and ACE, the removal cost within Accumulated depreciation was reclassified to the Regulatory liability or Regulatory asset account to align with Exelon's presentation. The reclassifications were not considered errors for PHI, Pepco, DPL or ACE.

During preparation of the June 30, 2016 financial statements, an error was identified related to the PHI successor period Consolidated Statement of Cash Flows for the period March 24, 2016 to March 31, 2016. The \$46 million classification error related to the presentation of changes in Receivables from and payables to affiliates, net within Cash flows from operating activities and Change in Exelon intercompany money pool within Cash flows from financing activities. This was corrected for the period of March 24, 2016 to June 30, 2016 and will be revised within the first quarter 2017 Form 10-Q when the March 24 to March 31, 2016 successor period will next be disclosed. As revised, the successor period statement of cash flows for the period March 24, 2016 to March 31, 2016 will present Cash flows used in operating activities of \$3 million, a decrease of \$46 million from the originally reported amount, and Cash flows used in financing activities of \$135 million, a decrease of \$46 million from the originally reported amount. Management has concluded that the error is not material to the previously issued financial statements.

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

In its December 31, 2015 Form 10-K, Exelon revised the presentation on the Consolidated Statements of Operations and Comprehensive Income for PECO and BGE to reflect separately operating revenues from the sale of electricity and operating revenues from the sale of natural gas, as well as to reflect separately purchased power expense and purchased fuel expense within the operating expenses section of the Consolidated Statement of Operations and Comprehensive Income. Further, Exelon revised the presentation from Total operating revenues to Rate-regulated utility revenues and Competitive businesses revenues on the face of Exelon's Consolidated Statement of Operations and Comprehensive Income for all periods presented. Similarly, Exelon has separately presented Rate-regulated utility purchased power and fuel expense and Competitive businesses purchased power and fuel expense on the face of Exelon's Consolidated Statement of Operations and Comprehensive Income for all periods presented. The reclassifications described herein were made for presentation purposes and did not affect any of the Registrants' total operating revenues or net income.

***ACE Basic Generation Service Recovery Mechanism***

ACE has a recovery mechanism for purchased power costs associated with BGS. ACE records a deferred energy supply costs regulatory asset or regulatory liability for under or over-recovered costs that are expected to be recovered from or refunded to ACE customers, respectively. In the first quarter of 2016, ACE changed its method of accounting for determining under or over-recovered costs in this recovery mechanism to include unbilled revenues in the determination of under or over-recovered costs. ACE believes this change is preferable as it better reflects the economic impacts of dollar-for-dollar cost recovery mechanisms. ACE applied the change retrospectively. The impact of the change was a \$12 million reduction to ACE's opening Retained earnings as of January 1, 2014 with a corresponding reduction to Regulatory assets. The impact of the change on Net income attributable to common shareholder is a decrease of \$4 million for the three months ended June 30, 2015 and an increase of \$1 million for the six months ended June 30, 2015.

***Classification of Interest on Uncertain Tax Positions***

In the first quarter of 2016, PHI, Pepco, DPL and ACE changed their accounting principle for classification of interest on uncertain tax positions. PHI, Pepco, DPL and ACE have reclassified interest on uncertain tax positions as interest expense from income tax expense in the Consolidated Statements of Operations and Comprehensive Income. GAAP does not address the preferability of one acceptable method of accounting over the other for the classification of interest on uncertain tax positions. However, PHI, Pepco, DPL, and ACE believe this change is preferable for comparability of their financial statements with the financial statements of the other Registrants in the combined filing, for consistency with FERC classification, and for a more appropriate representation of the effective tax rate as they manage the settlement of uncertain tax positions and interest expense separately. PHI, Pepco, DPL, and ACE applied the change retrospectively. The reclassification in the Consolidated Statements of Operations and Comprehensive Income for the three and six months ended June 30, 2015 is \$1 million for PHI and less than \$1 million for Pepco, DPL and ACE. The reclassification amount is more significant for the year ended December 31, 2015.

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

The accompanying consolidated financial statements as of June 30, 2016 and 2015 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, 2015 Consolidated Balance Sheets were obtained 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, 2016. These Combined Notes to Consolidated Financial

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

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 Pronouncements (All Registrants)**

Exelon has identified the following new accounting standards that have been recently adopted.

***Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share***

In May 2015, the FASB issued authoritative guidance that removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. Investments measured at net asset value per share using the practical expedient will be presented as a reconciling item between the fair value hierarchy disclosure and the investment line item on the Balance Sheet. The guidance also simplified the disclosure requirements for investments valued using the practical expedient. The guidance is effective for the Registrants for fiscal years beginning after December 15, 2015. The Registrants adopted the standard in the first quarter of 2016, and applied the guidance retrospectively to all prior periods presented. The adoption of this guidance had no impact on the Registrants Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income and Consolidated Statements of Cash Flows. See Note 8 – Fair Value of Financial Assets and Liabilities for the disclosure impacts.

***Customer s Accounting for Fees Paid in a Cloud Computing Arrangement***

In April 2015, the FASB issued authoritative guidance that clarifies the circumstances under which a cloud computing customer would account for the arrangement as a license of internal-use software. A cloud computing arrangement would include a software license if (1) the customer has a contractual right to take possession of the software at any time during the hosting period without significant penalty and (2) it is feasible for the customer to either operate the software on its own hardware or contract with another party unrelated to the vendor to host the software. If the arrangement does not contain a software license, it would be accounted for as a service contract. The Registrants prospectively adopted the standard in the first quarter of 2016. The adoption of this guidance had no impact on the Registrants Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures.

***Amendments to the Consolidation Analysis***

In February 2015, the FASB issued authoritative guidance that amends the consolidation analysis for variable interest entities (VIEs) as well as voting interest entities. The new guidance primarily (1) changes the VIE assessment of limited partnerships, (2) amends the effect that fees paid to a decision maker or service provider have on the VIE analysis, (3) amends how variable interests held by a reporting entity s related parties and de facto agents impact its consolidation conclusion, (4) clarifies how to determine whether equity holders (as a group) have power over an entity, and (5) provides a scope exception for registered and similar unregistered money market funds. The guidance became effective for the Registrants January 1, 2016. The Registrants adopted the standard in the first quarter of 2016. The Registrants have evaluated the standard and have not identified any changes to consolidation conclusions as a result of the new guidance. Based on the analysis completed, additional entities were considered VIEs. See Note 3 – Variable Interest Entities for the disclosure impacts.

The following issued accounting standards are not yet required to be reflected in the consolidated financial statements of the Registrants.

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**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)*****Revenue from Contracts with Customers***

In May 2014, the FASB issued authoritative guidance that changes the criteria for recognizing revenue from a contract with a customer. 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. 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 are currently assessing the impacts this guidance may have on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income and disclosures as well as the transition method that they will use to adopt the guidance. Exelon is considering the impacts of the new guidance on its ability to recognize revenue for certain contracts where collectability is in question, its accounting for contributions in aid of construction, bundled sales contracts and contracts with pricing provisions that may require it to recognize revenue at prices other than the contract price (e.g., straight line or estimated future market prices). In addition, the Registrants will be required to capitalize costs to acquire new contracts, whereas Exelon currently expenses those costs as incurred. The guidance 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. The Registrants do not plan to early adopt the standard. In March 2016, the FASB issued a final amendment to clarify the implementation guidance for principal versus agent considerations and in April 2016 issued a final amendment to clarify the guidance related to identifying performance obligations and the accounting for licenses of intellectual property. In May 2016, the FASB issued a final amendment regarding narrow scope improvements and practical expedients. The Registrants are currently assessing the impact of these updates.

***Leases***

In February 2016, the FASB issued authoritative guidance to increase 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 for fiscal years beginning after December 15, 2018 with early adoption permitted. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The Registrants are currently assessing 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 as well as the potential to early adopt the guidance.

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**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)*****Impairment of Financial Instruments***

In June 2016, the FASB issued authoritative guidance that adds an impairment model to U.S. GAAP called the Current Expected Credit Loss (CECL) model for financial instruments within the scope of the guidance, which includes loans, trade receivables, debt securities classified as Held to Maturity and net investments in leases recognized by a lessor. Under the new guidance, on initial recognition and at each reporting period, an entity would be 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. An entity must consider all available relevant information when estimating expected credit losses. Historical charge-off rates may be used as a starting point for determining expected credit losses; however, the entity must also evaluate how conditions that existed during the historical charge-off period may differ from its current expectations and accordingly revise its estimate of expected credit losses. The standard does not make changes to the existing impairment models for non-financial assets such as fixed assets, intangibles and goodwill. The standard also does not apply to Available for Sale Debt Securities. The standard will be effective January 1, 2020. The Registrants are currently assessing 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.

***Improvements to Employee Share-Based Payment Accounting***

In March 2016, the FASB issued authoritative guidance intended to simplify various aspects to how share-based payment awards to employees are accounted for and presented in the financial statements. The new guidance eliminates additional paid-in capital pools and requires excess tax benefits and tax deficiencies to be recorded in the Statement of Operations and Comprehensive Income. The standard is effective for fiscal years beginning after December 15, 2016 with early adoption permitted if all provisions are adopted within the same period. The guidance is required to be applied on either a prospective, modified retrospective, or retrospective basis depending on the provisions applied. The Registrants do not expect that this guidance will have a significant impact on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. The Registrants are currently assessing the potential to early adopt the guidance.

***Simplifying the Transition to the Equity Method of Accounting***

In March 2016, the FASB issued authoritative guidance eliminating the requirement to retroactively adopt the equity method of accounting as a result of an increase in the level ownership or degree of influence of an existing investment. The guidance now requires an investor to add the cost of acquiring the additional interest in the investee to the current basis of the investor's previously held interest and adopt the equity method of accounting as of the date the investment becomes qualified for the equity method of accounting. The standard is effective for fiscal years beginning after December 15, 2016 with early adoption permitted. The Registrants do not expect that this guidance will have a significant impact on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. The Registrants are currently assessing the potential to early adopt the guidance.

***Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships***

In March 2016, the FASB issued authoritative guidance which clarifies that a change in the counterparty of a derivative contract does not, in and of itself, require dedesignation of that hedge accounting relationship as long as all of the other hedge accounting criteria are met. The standard is effective for fiscal years beginning after December 15, 2016 with early adoption permitted. Entities have the option to adopt this standard on a prospective basis to new derivative contract novations or on a modified retrospective basis. The Registrants do

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

not expect that this guidance will have a significant impact on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. The Registrants are currently assessing the transition method and the potential to early adopt the guidance.

***Contingent Put and Call Options in Debt Instruments***

In March 2016, the FASB issued authoritative guidance which simplifies the embedded derivative analysis for debt instruments containing contingent call or put options by removing the requirement to assess whether a contingent event is related to interest rates or credit risks. The guidance clarifies that a contingent put or call option embedded in a debt instrument would be evaluated for possible separate accounting as a derivative instrument without regard to the nature of the exercise contingency. The standard is effective for fiscal years beginning after December 15, 2016 with early adoption permitted. The guidance is required to be applied on a modified retrospective basis to all existing and future debt instruments. The Registrants do not expect that this guidance will have a significant impact on Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures and are currently assessing the potential to early adopt the guidance.

***Recognition and Measurement of Financial Assets and Financial Liabilities***

In January 2016, the FASB issued authoritative guidance which (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 for fiscal years beginning after December 15, 2017 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). The Registrants are currently assessing 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 as well as the potential to early adopt the guidance.

***Simplifying the Measurement of Inventory***

In July 2015, the FASB issued authoritative guidance that requires inventory to be measured at the lower of cost or net realizable value. The new guidance defines net realizable value as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This definition is consistent with existing authoritative guidance. Current guidance requires inventory to be measured at the lower of cost or market where market could be replacement cost, net realizable value or net realizable value less an approximately normal profit margin. The guidance is effective for periods beginning after December 15, 2016 with early adoption permitted. The guidance is required to be applied prospectively. The Registrants do not expect that this guidance will have a significant impact on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. The Registrants are currently assessing the potential to early adopt the guidance.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****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, 2016, Exelon, Generation, BGE, PHI and ACE collectively consolidated nine VIEs or VIE groups for which the applicable Registrant was the primary beneficiary. At December 31, 2015, Exelon, Generation and BGE collectively had seven consolidated VIEs or VIE groups and PHI and ACE collectively had one consolidated VIE (*see Consolidated Variable Interest Entities below*). As of June 30, 2016 and December 31, 2015, Exelon and Generation collectively had significant interests in nine and eight other VIEs, respectively, for which the applicable Registrant does not have the power to direct the entities' activities and, accordingly, was not the primary beneficiary (*see Unconsolidated Variable Interest Entities below*).

***Consolidated Variable Interest Entities***

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 another distributed energy company. 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 will contribute a total of \$250 million of equity incrementally from inception through December 2016 in proportion to their ownership interests, which equates to approximately \$172 million for the tax equity investor and \$78 million for Generation (see Note 18 – Commitments and Contingencies for more details). The investment in the distributed energy company was evaluated, and it was determined to be a VIE for which Generation is not the primary beneficiary (see additional details in the Unconsolidated Variable Interest Entities section below). As of December 31, 2015, Generation consolidated 2015 ESA Investco, LLC under the voting interest model. However, pursuant to the new consolidation guidance effective as of January 1, 2016 for the Registrants, 2015 ESA Investco, LLC meets the definition of a VIE because the company has a similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner. (For additional details related to the new consolidation guidance, see Note 2 – New Accounting Pronouncements.) Under VIE guidance, Generation is the primary beneficiary; therefore, the entity continues to be consolidated.

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

A retail gas group formed by Generation to enter into a collateralized gas supply agreement with a third-party gas supplier,

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,

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

BondCo, a special purpose bankruptcy remote limited liability company formed by BGE to acquire, hold, issue and service bonds secured by rate stabilization property, 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, 2016 and December 31, 2015, ComEd, PECO, Pepco and DPL did not have any material consolidated VIEs.

As of June 30, 2016 and December 31, 2015, Exelon, Generation, BGE, 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.

Generation and Exelon, where indicated, provide the following support to CENG (see Note 5 Investment in Constellation Energy Nuclear Group, LLC and Note 26 Related Party Transactions of the Exelon 2015 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 have been suspended during the term of the Reliability Support Services Agreement (RSSA) (see Note 5 Regulatory Matters for additional details),

Generation provided a \$400 million loan to CENG. As of June 30, 2016, the remaining obligation is \$308 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 18 Commitments and Contingencies for more details),

in connection with CENG's severance obligations, Generation has agreed to reimburse CENG for a total of approximately \$6 million of the severance benefits paid or to be paid in 2014 through 2016. As of June 30, 2016, there was no remaining obligation,

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,

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

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 18 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.

Generation provides approximately \$13 million in credit support for the retail power and gas companies for which Generation is the sole supplier of energy.

Generation provides a \$75 million parental guarantee to a third-party gas supplier and provides limited recourse to other third-party gas suppliers and customers in support of its retail gas group.

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.

In the case of BondCo, BGE is required to remit all payments it receives from all residential customers through non-bypassable, rate stabilization charges to BondCo. During the three and six months ended June 30, 2016, BGE remitted \$21 million and \$42 million to BondCo, respectively. During the three and six months ended June 30, 2015, BGE remitted \$21 million and \$42 million to BondCo, respectively.

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, 2016, ACE transferred \$12 million and \$26 million to ATF, respectively. During the three and six months ended June 30, 2015, ACE transferred \$14 million and \$27 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;

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Exelon, Generation, BGE, PHI and ACE did not provide any additional material financial support to the VIEs;

Exelon, Generation, BGE, 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, BGE's, PHI's or ACE's general credit.

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

The carrying amounts and classification of the consolidated VIEs assets and liabilities included in the Registrants consolidated financial statements at June 30, 2016 and December 31, 2015 are as follows:

	June 30, 2016					December 31, 2015				
	Exelon <sup>(a)(b)</sup>	Generation	BGE	Successor PHI <sup>(b)</sup>	ACE	Exelon <sup>(a)</sup>	Generation	BGE	Predecessor PHI	ACE
Current assets	\$ 818	\$ 784	\$ 17	\$ 14	\$ 10	\$ 909	\$ 881	\$ 23	\$ 12	\$ 12
Noncurrent assets	8,083	8,048	3	31	19	8,009	8,004	3	18	18
<b>Total assets</b>	<b>\$ 8,901</b>	<b>\$ 8,832</b>	<b>\$ 20</b>	<b>\$ 45</b>	<b>\$ 29</b>	<b>\$ 8,918</b>	<b>\$ 8,885</b>	<b>\$ 26</b>	<b>\$ 30</b>	<b>\$ 30</b>
Current liabilities	\$ 597	\$ 464	\$ 82	48	\$ 44	\$ 473	\$ 387	\$ 81	\$ 48	\$ 48
Noncurrent liabilities	3,070	2,951		118	106	2,927	2,884	41	124	124
<b>Total liabilities</b>	<b>\$ 3,667</b>	<b>\$ 3,415</b>	<b>\$ 82</b>	<b>\$ 166</b>	<b>\$ 150</b>	<b>\$ 3,400</b>	<b>\$ 3,271</b>	<b>\$ 122</b>	<b>\$ 172</b>	<b>\$ 172</b>

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

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

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

(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, 2016 and December 31, 2015, these assets and liabilities primarily consisted of the following:

	June 30, 2016					December 31, 2015				
	Exelon <sup>(a)(b)</sup>	Generation	BGE	Successor PHI <sup>(b)</sup>	ACE	Exelon <sup>(a)</sup>	Generation	BGE	Predecessor PHI	ACE
Cash and cash equivalents	\$ 138	\$ 138	\$	\$	\$	\$ 164	\$ 164	\$	\$	\$
Restricted cash	53	26	17	10	10	100	77	23	12	12
Accounts receivable, net										
Customer	253	253				219	219			
Other	44	44				43	43			
Mark-to-market derivatives assets	41	41				140	140			
Inventory										
Materials and supplies	189	189				181	181			
Other current assets	37	30		4		35	30			
Total current assets	755	721	17	14	10	882	854	23	12	12
Property, plant and equipment, net	5,147	5,147				5,160	5,160			
Nuclear decommissioning trust funds	2,100	2,100				2,036	2,036			
Goodwill	47	47				47	47			
Mark-to-market derivatives assets	24	24				53	53			
Other noncurrent assets	167	133	3	31	19	90	85	3	18	18
Total noncurrent assets	7,485	7,451	3	31	19	7,386	7,381	3	18	18
Total assets	\$ 8,240	\$ 8,172	\$ 20	\$ 45	\$ 29	\$ 8,268	\$ 8,235	\$ 26	\$ 30	\$ 30
Long-term debt due within one year	\$ 312	\$ 183	\$ 81	\$ 46	\$ 42	\$ 111	\$ 27	\$ 79	\$ 46	\$ 46
Accounts payable	146	146				216	216			
Accrued expenses	79	76	1	2	2	115	113	2	2	2
Mark-to-market derivative liabilities	21	21				5	5			
Unamortized energy contract liabilities	13	13				12	12			
Other current liabilities	23	23				13	13			
Total current liabilities	594	462	82	48	44	472	386	81	48	48
Long-term debt	675	557		118	106	666	623	41	124	124
Asset retirement obligations	2,053	2,053				1,999	1,999			
Pension obligation <sup>(c)</sup>	9	9				9	9			
Unamortized energy contract liabilities	31	31				39	39			



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Other noncurrent liabilities	99	99				79	79			
Total noncurrent liabilities	2,867	2,749		118	106	2,792	2,749	41	124	124
Total liabilities	\$ 3,461	\$ 3,211	\$ 82	\$ 166	\$ 150	\$ 3,264	\$ 3,135	\$ 122	\$ 172	\$ 172

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

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

(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 balance sheet. 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 predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

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 energy development companies, distributed energy companies, and energy generating facilities for which Generation has concluded that consolidation is not required.

As of June 30, 2016 and December 31, 2015, Exelon and Generation had significant unconsolidated variable interests in nine and eight VIEs, respectively for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity investments and certain commercial agreements. Exelon and Generation only include unconsolidated VIEs that are individually material in the tables below. However, Generation has several individually immaterial VIEs that in aggregate represent a total investment of \$18 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 \$18 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 July 2014, Generation entered into an arrangement to purchase a 90% equity interest and 90% of the tax attributes of a distributed energy company. Generation's total equity commitment in this arrangement was \$91 million and was paid incrementally over an approximate two year period (see Note 18 Commitments and Contingencies for additional details). This arrangement did not meet the definition of a VIE and was recorded as an equity method investment. However, pursuant to the new consolidation guidance effective as of January 1, 2016 for the Registrants, the distributed energy company meets the definition of a VIE because the company has a similar structure to a limited partnership and the limited partners do not have kick out rights of the general partner. (For additional details related to the new consolidation guidance, see Note 2 New Accounting Pronouncements.) Generation is not the primary beneficiary; therefore, the investment continues to be recorded using the equity method.

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. Separate from the equity investment, Generation provided \$27 million in cash to the other (10%) equity holder in the distributed energy company in exchange for a convertible promissory note. In November 2015, Generation sold 69% of its equity interest in 2015 ESA Investco, LLC to a tax equity



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

investor. Generation and the tax equity investor will contribute a total of \$250 million of equity incrementally from inception through December 2016 in proportion of their ownership interests, which equates to approximately \$172 million for the tax equity investor and \$78 million for Generation (see Note 18 – Commitments and Contingencies for additional details). Generation and the tax equity investor provide 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, which is an unconsolidated VIE. The investment in the distributed energy company was evaluated and it was determined to be a VIE for which Generation is not the primary beneficiary. See additional details in the Consolidated Variable Interest Entities section above.

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

	<b>Commercial Agreement VIEs</b>	<b>Equity Investment VIEs</b>	<b>Total</b>
<b>June 30, 2016</b>			
Total assets <sup>(a)</sup>	\$ 503	\$ 395	\$ 898
Total liabilities <sup>(a)</sup>	106	281	387
Exelon’s ownership interest in VIE <sup>(b)</sup>		80	80
Other ownership interests in VIE <sup>(a)</sup>	397	34	431
Registrants’ maximum exposure to loss:			
Carrying amount of equity method investments		137	137
Contract intangible asset	9		9
Debt and payment guarantees		3	3
Net assets pledged for Zion Station decommissioning <sup>(b)</sup>	13		13

	<b>Commercial Agreement VIEs</b>	<b>Equity Investment VIEs</b>	<b>Total</b>
<b>December 31, 2015</b>			
Total assets <sup>(a)</sup>	\$ 263	\$ 164	\$ 427
Total liabilities <sup>(a)</sup>	22	125	147
Exelon’s ownership interest in VIE <sup>(b)</sup>		11	11
Other ownership interests in VIE <sup>(a)</sup>	241	28	269
Registrants’ maximum exposure to loss:			
Carrying amount of equity method investments		21	21
Contract intangible asset	9		9
Debt and payment guarantees		3	3
Net assets pledged for Zion Station decommissioning <sup>(b)</sup>	17		17

(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 \$161 million and \$206 million as of June 30, 2016 and December 31, 2015, respectively; offset by payables to ZionSolutions LLC of \$148 million and \$189 million as of June 30, 2016 and December 31, 2015, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

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For each of the unconsolidated VIEs, Exelon and Generation has 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.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**4. Mergers, Acquisitions and Dispositions (Exelon, Generation, PHI and Pepco)****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. Exelon estimates total commitments of approximately \$444 million on a net present value basis (excluding charitable contributions and renewable generation commitments) will be provided. The actual cost of commitments may differ by a material amount depending on the result of final negotiations and application of the most favored nation provision. The following pre-tax costs were recognized, including the estimated impacts of applying the most favored nation provision, after the closing of the merger and are included in Operating and maintenance expense in Exelon's, PHI's, Pepco's, DPL's and ACE's Consolidated Statements of Operations and Comprehensive Income for the six months ended June 30, 2016 and PHI's successor Consolidated Statements of Operations and Comprehensive Income:

Description	Expected		Successor				
	Payment	Period	Pepco	DPL	ACE	PHI	Exelon
Customer bill credit	2016	2017	\$ 65	\$ 58	\$ 62	\$ 185	\$ 185
Energy efficiency	2016	2021					64
Charitable contributions	2016	2026	28	12	10	50	50
Customer base rate credit	2016	2019	26			26	26
Delivery system modernization	Q2 2016						22
Green sustainability fund	Q2 2016						14
Workforce development	2016	2020					11
Most favored nation			19	32	48	99	129
Other			1	2		3	7
Total			\$ 139	\$ 104	\$ 120	\$ 363	\$ 508

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.



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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

In addition, Exelon is committed to develop or to assist in the commercial development of approximately 37 MWs of new generation in Maryland and the District of Columbia, 27 MWs of which are expected to be completed by 2018. These investments are expected to total approximately \$130 million, are expected to be primarily capital in nature, and will generate future earnings at Exelon and Generation. The actual cost of new generation may differ by a material amount depending on the result of final negotiations and application of the most favored nation provision. 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.

Exelon has been named in suits filed in the Delaware Chancery Court alleging that individual directors of PHI breached their fiduciary duties by entering into the merger transaction and Exelon aided and abetted the individual directors' breaches. The suits seek rescission of the merger. In addition, they also seek unspecified damages and costs. Exelon was also named in a federal court suit making similar claims. On June 1, 2016, the parties executed a settlement to resolve all claims, subject to the approval of the Delaware Court. Exelon does not believe resolution of these suits will have a material impact on Exelon's results of operations or cash flows.

On July 21, 2015, the OPC filed a motion to stay the MDPSC order approving the merger and to set a schedule for discovery and presentation of new evidence. On July 29, 2015, Public Citizen, Inc. filed a response supporting OPC's motion to stay, and on July 31, 2015 the Sierra Club and the Chesapeake Climate Action Network (CCAN) filed a joint motion to stay. In July and August, Exelon, PHI, the MDPSC, Prince George's County and Montgomery County filed responses opposing the motions to stay. The 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 a notice of appeal. Exelon believes the matters are without merit. These appeals are not expected to be resolved any earlier than the first quarter of 2017.

On March 25, 2016, Grid 2.0 filed an application for reconsideration of the DCPSC's March 23, 2016 order approving the merger. On March 30, 2016, Exelon filed a reply to that application. On April 20, 2016, DC Public Power filed a motion to reconsider the DCPSC's March 23, 2016 order, motion to intervene and motion to consider alternative settlement provisions (namely, that the DCPSC consider requiring the post-merger divestiture of Pepco's DC-based assets to a not-for-profit independent grid operator). On April 27, 2016, Exelon filed a reply to these motions. On April 22, 2016, (1) the District of Columbia Office of People's Counsel, (2) the District of Columbia Government, and (3) DC Sun and Public Citizen each filed separate applications for reconsideration of the DCPSC's March 23, 2016 order. On April 29, 2016, Exelon filed a reply to these applications. These applications for reconsideration generally argue that the DCPSC violated its regulations, utilized improper processes, abused its discretion, acted arbitrarily and capriciously, committed legal error and denied due process in approving the merger under terms that revised the Settlement Agreement offered by the companies and various parties. On June 17, 2016, the DCPSC denied all motions. The parties have until August 16, 2016 to appeal the DCPSC decision.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)***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:

<b>(In millions of dollars, except per share data)</b>	<b>Total Consideration</b>
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 <sup>(a)</sup>	180
Cash paid for PHI stock-based compensation equity awards <sup>(b)</sup>	29
 Total purchase price	 \$ 7,142

(a) As of December 31, 2015, the preferred stock was included in Other non-current assets on Exelon's Consolidated Balance Sheets.

(b) 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 valuations performed in the first quarter of 2016 to assess the fair value of certain assets acquired and liabilities assumed were considered preliminary as a result of the short time period between the closing of the merger and the end of the first quarter of 2016. Accounting guidance provides that the allocation of the purchase price may be modified up to one year from the date of the merger as more information is obtained about the fair value of assets acquired and liabilities assumed; however, Exelon expects to finalize these amounts by the end of 2016, if not sooner. During the second quarter, certain modifications were made to preliminary valuation amounts for acquired unamortized energy contracts, long-term debt and pension and OPEB liability resulting in an \$8 million net increase to goodwill. The preliminary amounts recognized are subject to further revision to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date. Any changes to the fair value assessments may affect the purchase price allocation and could potentially impact goodwill.

**Table of Contents****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:

**Preliminary Purchase Price Allocation**

Current assets	\$ 1,441
Property, plant and equipment	11,076
Regulatory assets	5,015
Other assets	248
Goodwill	4,024
 Total assets	 \$ 21,804
Current liabilities	\$ 2,763
Unamortized energy contracts	1,515
Regulatory liabilities	297
Long-term debt, including current maturities	5,636
Deferred income taxes	3,443
Pension and OPEB liability	821
Other liabilities	187
 Total liabilities	 \$ 14,662
 Total purchase price	 \$ 7,142

During preparation of the June 30, 2016 financial statements, an error was identified related to the preliminary purchase price allocation table above as originally reported in the first quarter 2016 Form 10-Q. The error resulted in a gross up of certain assets and liabilities related to legacy PHI intercompany and income tax receivable and payable balances that were not properly reflected in the first quarter 2016 Form 10-Q disclosure, with no impact on reported net assets acquired or goodwill. The correction of the disclosure error has been reflected in the table presented above. As revised, the Current assets, Other assets, Current liabilities, Long-term debt, including current maturities, Deferred income taxes, and Other liabilities would have been disclosed as \$1,441 million, \$249 million, \$2,764 million, \$5,661 million, \$3,448 million and \$187 million, respectively, within the first quarter 2016 Form 10-Q. Management has concluded that the disclosure error is not material to the previously issued financial statements.

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, \$1.2 billion and \$1.1 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.



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

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 and impacts of utility rate regulation. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired.

Exelon's and PHI's carrying amount of goodwill for the six months ended June 30, 2016 was as follows:

	PHI	Exelon <sup>(a)</sup>
Beginning balance	\$	\$ 2,672
Goodwill from business combination	4,016	4,016
Measurement period adjustment	8	8
Ending balance	\$ 4,024	\$ 6,696

(a) As of June 30, 2016, there were no changes to the carrying amount of goodwill for ComEd and Generation, see Note 11 Intangible Assets of the Exelon 2015 Form 10-K for further information.

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.

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, 2016. 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.



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

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 Operating revenues of \$1,112 million and Net income of \$52 million during the three months ended June 30, 2016, and Operating revenues of \$1,219 million and Net loss of \$(262) million during the six months ended June 30, 2016.

For the three and six months ended June 30, 2016 and 2015, the Registrants have recognized costs to achieve the PHI acquisition as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
<b>Acquisition, Integration and Financing Costs<sup>(a)</sup></b>				
Exelon <sup>(b)</sup>	\$ 1	\$ (87)	\$ 103	\$ 21
Generation	4	7	20	15
ComEd <sup>(c)</sup>	1	3	(7)	6
PECO	1	1	2	2
BGE <sup>(d)</sup>	(5)	1	(4)	3
Pepco <sup>(d)</sup>	(4)	1	23	2
DPL <sup>(d)</sup>		1	16	1
ACE	2	1	15	1

Acquisition, Integration and Financing Costs <sup>(a)</sup>	Successor	Predecessor	Successor	Predecessor	
	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	March 24, 2016 to June 30, 2016	January 1, 2016 to March 23, 2016	Six Months Ended June 30, 2015
PHI <sup>(d)</sup>	\$ (1)	\$ 5	\$ 55	\$ 29	\$ 14

(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 has 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, \$9 million, \$3 million and \$12 million incurred at BGE, Pepco, DPL and PHI, respectively, 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.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(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,		Six Months Ended June 30,		Year Ended December 31,
	2016 <sup>(a)</sup>	2015 <sup>(b)</sup>	2016 <sup>(a)</sup>	2015 <sup>(b)</sup>	2015 <sup>(c)</sup>
Total operating revenues	\$ 6,910	\$ 7,522	\$ 15,466	\$ 17,584	\$ 33,823
Net income attributable to common shareholders	268	623	845	1,423	2,618
Basic earnings per share	\$ 0.29	\$ 0.68	\$ 0.92	\$ 1.55	\$ 2.85
Diluted earnings per share	0.29	0.67	0.91	1.54	2.84

- (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 \$(82) million and \$35 million and intercompany revenue of \$111 million and \$233 million for the three and six months ended June 30, 2015, respectively.
- (c) The amounts above include adjustments for non-recurring costs directly related to the merger of \$92 million and intercompany revenue of \$559 million for the year ended December 31, 2015.

**Proposed Acquisition of ConEdison Solutions (Exelon and Generation)**

On July 27, 2016, Generation entered into an Asset Purchase Agreement (the Purchase Agreement) with ConEdison Solutions, a subsidiary of Consolidated Edison, Inc. (collectively ConEdison). Pursuant to the Purchase Agreement, ConEdison Solutions agreed to sell its competitive retail electric and natural gas business to Generation for an all cash purchase price of \$53 million plus estimated purchase price adjustments, including net working capital, of \$130 million. Pursuant to the Purchase Agreement, Generation has agreed to use its commercially reasonable efforts to replace the guarantees and other credit support currently being provided by ConEdison in support of the ongoing competitive retail electric and natural gas business and to reimburse ConEdison for any payments arising pursuant to such arrangements continuing for any post-closing period. The renewable energy, sustainable services and energy efficiency businesses of ConEdison are excluded from the transaction.

The transaction is expected to close in the third or fourth quarter of 2016. The closing of the transaction is subject to certain conditions, including, obtaining the termination or expiration of any applicable waiting period required under the HSR Act for the consummation of the transaction. Either party may terminate the Purchase Agreement if the transaction has not been consummated within six months after the date of the Purchase Agreement. The Purchase Agreement also includes various representations, warranties, covenants, indemnifications and other provisions customary for a transaction of this nature. The total costs directly related to the closing of the transaction are not expected to have a material impact on the financial results of Exelon and Generation.

The transaction is expected to be accounted for as a business combination. Therefore, Generation will record the fair value of the assets acquired and liabilities assumed as of the acquisition date. To the extent the purchase price is greater than the fair value of the net assets acquired, goodwill will be recorded. To the extent the fair value of the net assets acquired is greater than the purchase price, a bargain purchase gain will be recorded.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****Proposed Acquisition of James A. FitzPatrick Nuclear Generating Station (Exelon and Generation)**

On August 8, 2016, Generation executed a series of agreements with Entergy Nuclear FitzPatrick LLC (Entergy) to acquire the 838MW single-unit James A. FitzPatrick (FitzPatrick) nuclear generating station located in Scriba, New York for a cash purchase price of \$110 million. As part of the transaction, Generation would receive the FitzPatrick NDT fund assets and assume the obligation to decommission FitzPatrick. Closing of the transaction is currently anticipated to occur in the second quarter of 2017 and is dependent upon regulatory approval by FERC, NRC and the New York Public Service Commission (NYPS). The transaction is also subject to the notification and reporting requirements of the HSR Act and other customary closing conditions. The NRC license for FitzPatrick expires in 2034. Entergy had previously announced plans in November 2015 to early retire FitzPatrick at the end of the current fuel cycle in January 2017. Under the terms of the agreements, Generation will reimburse Entergy for approximately \$200 million to \$250 million of incremental costs to refuel the plant and operate and maintain the plant after the refueling outage, scheduled to end in February 2017, through the closing date. These are costs which otherwise would have been avoided by FitzPatrick's planned permanent shutdown in January 2017, a portion of which for financial reporting purposes will be evaluated as part of the purchase price consideration. Generation will be entitled to all revenues from FitzPatrick's electricity and capacity sales for the period commencing upon completion of the refueling outage through the acquisition closing date. The agreements provide for certain termination rights, including the right of either party to terminate if the transaction has not been consummated within 12 months due to failure to obtain the required regulatory approvals.

The transaction is expected to be accounted for as a business combination. Therefore, Generation will record the fair value of the assets acquired and liabilities assumed as of the acquisition date. To the extent the purchase price is greater than the fair value of the net assets acquired, goodwill will be recorded. To the extent the fair value of the net assets acquired is greater than the purchase price, a bargain purchase gain will be recorded.

**Asset Divestitures (Exelon, Generation, PHI and Pepco)**

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.

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. See Note 10 Debt and Credit Agreements for more information. As a result, \$61 million of Property, plant and equipment and \$5 million of Asset retirement obligation were reclassified as held for sale within Other current assets and Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

**5. Regulatory Matters (All Registrants)**

Except for the matters noted below, the disclosures set forth in Note 3 Regulatory Matters of the Exelon 2015 Form 10-K and Note 7 Regulatory Matters of the PHI 2015 Form 10-K appropriately represent, 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, 2016, ComEd filed its annual distribution formula rate with the ICC pursuant to EIMA. The filing establishes the revenue requirement used to set the rates



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that will take effect in January 2017 after the ICC's review and approval, which is due by December 2016. The revenue requirement requested is based on 2015 actual costs plus projected 2016 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2015 to the actual costs incurred that year. ComEd's 2016 filing request includes a total increase to the revenue requirement of \$138 million, reflecting an increase of \$139 million for the initial revenue requirement for 2017 and a decrease of \$1 million related to the annual reconciliation for 2015. The revenue requirement for 2017 provides for a weighted average debt and equity return on distribution rate base of 6.71% inclusive of an allowed ROE of 8.64%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2015 provided for a weighted average debt and equity return on distribution rate base of 6.69% inclusive of an allowed ROE of 8.59%, reflecting the average rate on 30-year treasury notes plus 580 basis points less a performance metrics penalty of 5 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 2015 Form 10-K.

**Grand Prairie Gateway Transmission Line (Exelon and ComEd).** On December 2, 2013, ComEd filed a request to obtain the ICC's approval to construct a 60-mile overhead 345kV transmission line that traverses Ogle, DeKalb, Kane and DuPage Counties in Northern Illinois. On October 22, 2014, the ICC issued an Order approving ComEd's request. The City of Elgin and certain other parties each filed an appeal of the ICC Order in the Illinois Appellate Court for the Second District. ComEd then reached a settlement of the appeal filed by all parties except Elgin. On March 31, 2016, the Illinois Appellate Court issued its opinion affirming the ICC's grant of a certificate to ComEd to construct and operate the line. Elgin did not seek further review of the Illinois Appellate Court decision. On May 28, 2014, in a separate proceeding, FERC issued an order granting ComEd's request to include 100% of the capital costs recorded to construction work in progress during construction of the line in ComEd's transmission rate base. If the project is cancelled or abandoned for reasons beyond ComEd's control, FERC approved the ability for ComEd to recover 100% of its prudent costs incurred after May 21, 2014 and 50% of its costs incurred prior to May 21, 2014 in ComEd's transmission rate base. The costs incurred for the project prior to May 21, 2014 were immaterial. ComEd has acquired numerous easements across the project route through voluntary transactions. ComEd is seeking to acquire the remaining rights either through settlement or condemnation proceedings that are currently pending in the relevant circuit courts. ComEd began construction of the line during 2015 with an expected in-service date of 2017.

**FutureGen Industrial Alliance, Inc (Exelon and ComEd).** During 2013, the ICC approved, and directed ComEd and Ameren (the Utilities) to enter into 20-year sourcing agreements with FutureGen Industrial Alliance, Inc (FutureGen), under which FutureGen will retrofit and repower an existing plant in Morgan County, Illinois to a 166 MW near zero emissions coal-fueled generation plant, with an assumed commercial operation date in 2017. The order also directs ComEd and Ameren to recover these costs from their electric distribution customers through the use of a tariff, regardless of whether they purchase electricity from ComEd or Ameren, or from competitive electric generation suppliers.

In February 2013, ComEd filed an appeal with the Illinois Appellate Court questioning the legality of requiring ComEd to procure power for retail customers purchasing electricity from competitive electric generation suppliers. On July 22, 2014, the Illinois Appellate Court issued its ruling re-affirming the ICC's order requiring ComEd to enter into the sourcing agreement with FutureGen and allowing the use of a tariff to recover its costs. ComEd decided not to appeal the Illinois Appellate Court's decision to the Illinois Supreme Court. However, the competitive electric generation suppliers and several large consumers petitioned for leave to appeal the Illinois Appellate Court's decision. On November 26, 2014, the Illinois Supreme Court granted the petition. ComEd executed the sourcing agreement with FutureGen in accordance with the ICC's order. In addition, ComEd filed a petition with the ICC seeking approval of the tariff allowing for the recovery of its costs associated with the FutureGen contract from all of its electric distribution customers, which was approved by the ICC on September 30, 2014.

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In February 2015, the DOE suspended funding for the cost development of FutureGen. On January 13, 2016, FutureGen informed the Illinois Supreme Court that it had ceased all development efforts on the FutureGen project. Accordingly, FutureGen requested that the court dismiss the proceeding as moot. In February 2016, FutureGen terminated its sourcing agreement with ComEd. On May 19, 2016, the Illinois Supreme Court dismissed the matter as moot. As a result, ComEd is under no further obligation under this agreement.

**Pennsylvania Regulatory Matters**

***Pennsylvania Procurement Proceedings (Exelon and PECO).*** Through PECO's first two PAPUC approved DSP Programs, PECO procured electric supply for its default electric customers through PAPUC approved competitive procurements. DSP I and DSP II expired on May 31, 2013 and May 31, 2015, respectively.

The second DSP Program included a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to submit a plan to allow its low-income CAP customers to purchase their generation supply from EGSs beginning in April 2014. In May 2013, PECO filed its CAP Shopping Plan with the PAPUC. By an Order entered on January 24, 2014, the PAPUC approved PECO's plan, with modifications, to make CAP shopping available beginning April 15, 2014. On March 20, 2014, the Office of Consumer Advocate (OCA) and low-income advocacy groups filed an appeal and emergency request for a stay with the Pennsylvania Commonwealth Court (Court), claiming that the PAPUC-ordered CAP Shopping plan does not contain sufficient protections for low-income customers. On July 14, 2015, the Court issued opinions on the OCA and low-income advocacy group appeal. Specifically, the Court remanded the issue to the PAPUC with instructions that it approve a rule revision to the PECO CAP Shopping Plan that would prohibit CAP customers from entering into contracts with an EGS that would impose early cancellation/termination fees. The PAPUC, as well as the low-income advocates and the Office of Consumer Advocate, appealed the Court's decision. On April 5, 2016, the Pennsylvania Supreme Court declined to accept the appeals. On May 11, 2016, the PAPUC issued a Secretarial Letter requiring PECO to propose a rule revision to the PECO CAP Shopping Plan consistent with the Court's decision. On July 19, 2016, PECO filed a letter stating its intent to revise its Plan by September 1, 2016 to incorporate the rule revision.

On December 4, 2014, the PAPUC approved PECO's third DSP Program. The program has a 24-month term from June 1, 2015 through May 31, 2017, and complies with electric generation procurement guidelines set forth in Act 129. Under the program, PECO is procuring electric supply through four competitive procurements for fixed price full requirements contracts of two years or less for the residential classes and small and medium commercial classes and spot market price full requirement contracts for the large commercial and industrial class load. Beginning in June 2016, the medium commercial class (101-500 kW) moved to spot market pricing. As of June 30, 2016, PECO entered into contracts with PAPUC-approved bidders, including Generation, resulting from the first three of its four scheduled procurements. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO's Consolidated Statement of Operations and Comprehensive Income.

On March 17, 2016, PECO filed its fourth DSP Program with the PAPUC. The program has a 24-month term from June 1, 2017 through May 31, 2019, and complies with electric generation procurement guidelines set forth in Act 129. A PAPUC ruling is expected in late 2016.

For further information on the Pennsylvania procurement proceedings, see Note 3 Regulatory Matters of the Exelon 2015 Form 10-K.

***Energy Efficiency Programs (Exelon and PECO).*** On June 19, 2015, the PAPUC issued its Phase III EE&C implementation order that provides energy consumption reduction requirements for the third phase of Act 129's EE&C program with a five-year term from June 1, 2016 through May 31, 2021.

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

Pursuant to the Phase III implementation order, PECO filed its five-year EE&C Phase III Plan with the PAPUC on November 30, 2015. The Plan sets forth how PECO will reduce electric consumption by at least 1,962,659 MWh, with a goal of 2,100,875 MWh in its service territory for the period June 1, 2016 through May 31, 2021. The PAPUC approved PECO's EE&C Phase III Plan, with requested clarifications, on May 19, 2016.

For further information on energy efficiency programs, see Note 3 Regulatory Matters of the Exelon 2015 Form 10-K.

**Maryland Regulatory Matters**

**2016 Maryland Electric Distribution Rate Case (Exelon, PHI and Pepco).** On April 19, 2016, Pepco filed an application with the MDPSC requesting an increase of \$127 million to its annual service revenues for electric delivery, based on a requested ROE of 10.6%. The application is inclusive of a request seeking recovery of Pepco's regulatory assets associated with its AMI program over a five year period. Any adjustments to rates approved by the MDPSC are expected to take effect in November 2016. Pepco cannot predict how much of the requested increase the MDPSC will approve. In addition to the proposed \$127 million rate increase, Pepco is proposing to continue its Grid Resiliency Program initially approved in July 2013 in connection with Pepco's electric distribution rate case filed in November 2012. Under the Grid Resiliency Program, Pepco is authorized to receive recovery of specific investments as the assets are placed in service through the Grid Resiliency Charge. In connection with the Grid Resiliency Program, Pepco proposes to accelerate improvement to priority feeders and install single-phase reclosing fuse technology by investing \$16 million a year for two years for a total of \$32 million. Pepco cannot predict whether the MDPSC will approve or if it will approve a continuation of Pepco's Grid Resiliency Program proposal.

**2016 Maryland Electric Distribution Base Rates (Exelon, PHI and DPL).** On July 20, 2016, DPL filed an application with the MDPSC requesting an increase of \$66 million to its electric distribution base rates, based on a requested ROE of 10.6%. The application is inclusive of a request seeking recovery of DPL's regulatory assets associated with its AMI program over a five year period. Any adjustments to rates approved by the MDPSC are expected to take effect in February 2017. DPL cannot predict how much of the requested increase the MDPSC will approve. In addition to the proposed \$66 million rate increase, DPL is proposing to continue its Grid Resiliency Program initially approved in September 2013 in connection with DPL's electric distribution rate case filed in February 2013. Under the Grid Resiliency Program, DPL is authorized to receive recovery of specific investments as the assets are placed in service through the Grid Resiliency Charge. In connection with the Grid Resiliency Program, DPL proposes to accelerate improvement to priority feeders and install single-phase reclosing fuse technology by investing \$4.6 million a year for two years for a total of \$9.2 million. DPL cannot predict whether the MDPSC will approve a continuation of DPL's Grid Resiliency Program proposal.

**2015 Maryland Electric and Natural Gas Distribution Rate Case (Exelon and BGE).** On November 6, 2015, and as amended through the course of the proceeding, BGE filed for electric and natural gas base rate increases with the MDPSC, ultimately requesting annual increases of \$116 million and \$78 million respectively, of which \$104 million and \$37 million, were related to recovery of electric and natural gas smart grid initiative costs, respectively. BGE also proposed to recover an annual increase of approximately \$30 million for Baltimore City underground conduit fees through a surcharge.

On June 3, 2016, the MDPSC issued an order in which the MDPSC found compelling evidence to conclude that BGE's smart grid initiative overall was cost beneficial to customers. However, the June 3 order contained several cost disallowances and adjustments, including not allowing BGE to defer or recover through a surcharge the \$30 million increase in annual Baltimore City underground conduit fees. On June 30, 2016, BGE filed a

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petition for rehearing of the June 3 order requesting that the MDPSC modify its order to reverse certain decisions including the decision associated with the Baltimore City underground conduit fees. OPC also subsequently filed for a petition for rehearing of the June 3 order.

On July 29, 2016, the MDPSC issued an order on the petitions for rehearing that reversed certain of its prior cost disallowances and adjustments related to the smart grid initiative. Through the combination of the orders, the MDPSC authorized electric and natural gas rate increases of \$44 million and \$48 million, respectively, and an allowed ROE for the electric and natural gas distribution businesses of 9.75% and 9.65%, respectively; and the new electric and natural gas base rates took effect for service rendered on or after June 4, 2016. However, MDPSC's July 29 order on the petition on rehearing still did not allow BGE to defer or recover through a surcharge the increase in Baltimore City underground conduit fees. BGE is evaluating its options as to the outstanding issues in its petition for rehearing. Refer to the Smart Meter and Smart Grid Investment disclosure below for further details on the impact of the ultimate disallowances contained in the orders to BGE.

**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, 2016 and December 31, 2015, BGE recorded a regulatory asset of \$240 million and \$196 million, respectively, representing incremental program costs, including a debt return thereon, and at June 30, 2016, \$56 million of unamortized costs of the non-AMI meters replaced under the program. The balance as of June 30, 2016, reflects the impact of the cost disallowances and adjustments discussed below. This regulatory asset is being recovered through rates and amortized to expense over 10 years. As part of rate base, the regulatory asset is earning a return except for the \$56 million portion reflecting the unamortized cost of the retired non-AMI meters and a \$32 million portion related to post-test year incremental program costs.

As part of the 2015 electric and natural gas distribution rate case filed on November 6, 2015, BGE sought recovery of its smart grid initiative costs, supported by evidence demonstrating that the benefits exceed the costs on a present value basis by a ratio of more than 2.0 to 1.0. On June 3, 2016, the MDPSC issued an order concluding that the smart grid initiative overall is cost beneficial to its customers. However, the June 3 order contained several cost disallowances and adjustments including disallowances of certain program and meter installation costs and denial of recovery of any return on unrecovered costs for non-AMI meters replaced under the program. On June 30, 2016, BGE filed a petition for rehearing of the June 3 order requesting that the MDPSC modify its order to reverse certain decisions and change certain of the cost disallowances and adjustments to enable BGE to defer those costs for recovery through future electric and natural gas rates. OPC also subsequently filed for a petition for rehearing of the June 3 order. On July 29, 2016, the MDPSC issued an order on the petitions for rehearing that reversed certain of its prior cost disallowances and adjustments related to the smart grid initiative. BGE is evaluating its options as to the outstanding issues in its petition for rehearing.

As a combined result of the MDPSC orders, BGE recorded a \$52 million charge 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. Pursuant to the combined MDPSC orders, BGE also 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 as of June 30, 2016. For further information, see Note 3 Regulatory Matters of the Exelon 2015 Form 10-K.

**2013 Maryland Electric and Natural Gas Distribution Rate Case (Exelon and BGE).** On May 17, 2013, and as amended on August 23, 2013, BGE filed for electric and natural gas base increases with the MDPSC. In

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addition to these requested rate increases, BGE's application also included a request for recovery of incremental capital expenditures and operating costs associated with BGE's proposed short-term reliability improvement plan (the ERI initiative) in response to a MDPSC order through a surcharge separate from base rates.

On December 13, 2013, the MDPSC issued an order authorizing BGE to recover through a surcharge mechanism costs associated with five ERI initiative programs designed to accelerate electric reliability improvements premised upon the condition that the MDPSC approve specific projects in advance of cost recovery. As of June 30, 2016, BGE has received approval of its updated surcharge filings three times for rates to be effective in 2014, 2015 and 2016.

In January 2014, the residential consumer advocate in Maryland filed an appeal to the order issued by the MDPSC on December 13, 2013 in BGE's 2013 electric and natural gas distribution rate cases. The residential consumer advocate filed its related legal memorandum on August 22, 2014, challenging the MDPSC's approval of the ERI initiative surcharge. BGE submitted a response to the appeal on October 15, 2014, and a hearing was held on November 17, 2014. On October 26, 2015, the Circuit Court for Baltimore City issued an order affirming the MDPSC decision. However, on November 23, 2015, the residential consumer advocate filed an appeal of the Circuit Court's decision with the Maryland Court of Special Appeals. On March 7, 2016, the consumer advocate withdrew its appeal and no further action is expected.

**MDPSC New Generation Contract Requirement (Exelon, Generation, BGE, PHI, Pepco and DPL).** On April 12, 2012, the MDPSC issued an order that requires BGE, Pepco and DPL (collectively, the Contract EDCs) to negotiate and enter into a contract with the winning bidder of a competitive bidding process to build one new power plant in the range of 650 to 700 MWs beginning in 2015, in amounts proportional to their relative SOS loads. Under the terms of the order, the winning bidder was to construct a 661 MW natural gas-fired combined cycle generation plant in Waldorf, Maryland, with an expected commercial operation date of June 1, 2015, and each of the Contract EDCs was to recover its costs associated with the contract through surcharges on its respective SOS customers.

In response to a complaint filed by a group of generating companies in the PJM region, on September 30, 2013, the U.S. District Court for the District of Maryland issued a ruling that the MDPSC's April 2012 order violated the Supremacy Clause of the U.S. Constitution by attempting to regulate wholesale prices. In contrast, on October 1, 2013, in response to appeals filed by the Contract EDCs and other parties, the Maryland Circuit Court for Baltimore City upheld the MDPSC's orders requiring the Contract EDCs to enter into the contracts.

On October 24, 2013, the Federal district court issued an order ruling that the contracts are illegal and unenforceable. In November 2013 both the winning bidder and the MDPSC appealed the Federal district court decision to the U.S. Court of Appeals for the Fourth Circuit, which affirmed the lower Federal court ruling. On November 26, 2014, both the winning bidder and the MDPSC petitioned the U.S. Supreme Court to consider hearing an appeal of the Fourth Circuit decision. On October 19, 2015, the U.S. Supreme Court agreed to review the decision. On April 19, 2016, the U.S. Supreme Court unanimously affirmed the Fourth Circuit's ruling upholding the Federal district court's decision.

The decision of the Maryland Circuit Court was appealed to the Maryland Court of Special Appeals and was stayed pending decision by the U.S. Supreme Court. On August 1, 2016, the Contract EDCs submitted a filing requesting that the MDPSC take notice of the U.S. Supreme Court's decision, and notifying the MDPSC that the Contract EDCs will dismiss their appeal pending at the Maryland Court of Special Appeals.

**Delaware Regulatory Matters**

**2016 Electric and Natural Gas Distribution Base 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 and \$22 million, respectively, based on a requested ROE of 10.6%. While the DPSC is not required to

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

issue a decision on the application within a specified period of time, Delaware law allows DPL to put into effect \$2.5 million of the rate increase two months after filing the application and the entire requested rate increase seven months after filing, subject to a cap and a refund obligation based on the final DPSC order. DPL cannot predict how much of the requested increase the DPSC will approve.

**2013 Electric Distribution Base Rates (Exelon, PHI and DPL).** In March 2013, and as amended on September 20, 2013, DPL filed for an electric distribution base rate increase with the DPSC, ultimately requesting an annual increase of \$42 million.

In August 2014, the DPSC issued a final order in DPL's 2013 electric distribution rate case for an annual increase of \$15 million and an ROE of 9.70%. Rates became effective on May 1, 2014.

In September 2014, DPL filed an appeal with the Delaware Superior Court of the DPSC's August 2014 order in this proceeding, seeking the court's review of the DPSC's decision relating to the recovery of costs associated with one component of employee compensation, certain retirement benefits and credit facility expenses. The Division of the Public Advocate filed a cross-appeal in September 2014, pertaining to the treatment of a prepaid pension expense and other postretirement benefit obligations in base rates. Under the Settlement Agreement related to the Merger, the parties agreed to suspend the appeal and, upon consummation of the Merger, to the withdrawal of the appeal and the cross-appeal with prejudice. In accordance with the settlement, on April 13, 2016, the parties filed a Stipulation of Dismissal with the court to dismiss the appeal and the cross-appeal, and the case is now closed.

**District of Columbia Regulatory Matters**

**2016 Electric Distribution Base 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, based on a requested ROE of 10.6%. Pepco has requested that the DCPSC issue a final decision by May 29, 2017. Any adjustments to its rates approved by the DCPSC are expected to take effect in June 2017. Pepco cannot predict how much of the requested increase the DCPSC will approve.

**District of Columbia Power Line Undergrounding Initiative (Exelon, PHI and Pepco).** In May 2014, the Council of the District of Columbia enacted the Electric Company Infrastructure Improvement Financing Act of 2014 (the Improvement Financing Act), which provided enabling legislation for the District of Columbia Power Line Undergrounding (DC PLUG) initiative. This \$1 billion initiative seeks to selectively place underground some of the District of Columbia's most outage-prone power lines, which lines and surrounding conduit would be owned and maintained by Pepco.

The Improvement Financing Act provides that: (i) Pepco is to fund approximately \$500 million of the estimated cost to complete the DC PLUG initiative, recovering those costs through a surcharge on the electric bills of Pepco District of Columbia customers; (ii) \$375 million of the DC PLUG initiative cost is to be financed by the District of Columbia's issuance of securitized bonds, which bonds will be repaid through a surcharge on the electric bills of Pepco District of Columbia customers that Pepco will remit to the District of Columbia; and (iii) the remaining costs up to \$125 million are to be covered by the existing capital projects program of the District of Columbia Department of Transportation (DDOT). Pepco will not earn a return on or a return of the cost of the assets funded with the proceeds of the securitized bonds or assets that are constructed by DDOT under its capital projects program, but ownership and responsibility for the operation and maintenance of such assets will be transferred to Pepco for a nominal amount.

In June 2014, Pepco and DDOT filed a Triennial Plan related to the construction of selected underground feeders in the District of Columbia and recovery of Pepco's investment through a volumetric surcharge (the Triennial Plan), all in accordance with the Improvement Financing Act. In August 2014, Pepco filed an



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

application for the issuance of a financing order to provide for the issuance of the District's bonds and a volumetric surcharge for the District to recover the costs associated with the bond issuance (the DDOT surcharge).

In March 2015, a party to the DCPSC proceedings filed with the District of Columbia Court of Appeals a petition for review of the order approving the Triennial Plan and the issuance of the financing order. On January 14, 2016, the District of Columbia Court of Appeals affirmed the orders of the DCPSC. On January 27, 2016, the original petitioning party sought rehearing of the District of Columbia Court of Appeals decision. On March 17, 2016, the District of Columbia Court of Appeals denied the original petitioning party's motion for rehearing.

Separately, in June 2015, an agency of the federal government served by Pepco asserted that the DDOT surcharge constitutes a tax on end users from which the federal government is immune. PHI is currently evaluating the assertion and the resolution of this matter will likely further delay implementation of the DC PLUG initiative.

**New Jersey Regulatory Matters**

**2016 Electric Distribution Base Rates (Exelon, PHI and ACE).** On March 22, 2016, as supplemented and updated on May 10, 2016, ACE filed an application with the NJBPU requesting an increase of \$85 million (including New Jersey sales and use tax) to its annual service revenues for electric delivery, based on a requested ROE of 10.6%. In addition to the request for base rate relief, ACE has also included a request that the NJBPU approve ACE's five-year grid resiliency initiative known as PowerAhead. As proposed, PowerAhead includes \$176 million of capital investments to advance modernization of the electric grid through energy efficiency, increased distributed generation, and resiliency, focused on improving the distribution system's ability to withstand major storm events. A decision is expected in the first half of 2017. ACE cannot predict how much of the requested increase the NJBPU will approve or if it will approve ACE's PowerAhead initiative.

**Update and Reconciliation of Certain Under-Recovered Balances (Exelon, PHI and ACE).** On February 1, 2016, ACE submitted its 2016 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 NUGs 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.

The net impact of adjusting the charges as proposed is an overall annual rate increase of \$9 million (revised to \$19 million in April 2016, based upon an update for actuals through March 2016), including New Jersey sales and use tax. The matter is pending at the NJBPU.

**Standard Offer Capacity Agreements (Exelon, PHI and ACE).** On April 28, 2011, ACE entered into three SOCAs by order of the NJBPU, each with a different generation company. ACE and the other New Jersey EDCs entered into the SOCAs under protest, arguing that the EDCs were denied due process and that the SOCAs violated certain of the requirements of the New Jersey law under which the SOCAs were established (the NJ SOCA Law). On October 22, 2013, in light of the decision of the U.S. District Court for the District of New Jersey described below, the state appeals of the NJBPU implementation orders filed by the EDCs and generators were dismissed without prejudice, subject to the parties exercising their appellate rights in the Federal courts.

In February 2011, ACE joined other plaintiffs in an action filed in the U.S. District Court for the District of New Jersey challenging the NJ SOCA Law on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. In October 2013, the Federal district court issued a ruling that the NJ SOCA Law is preempted by the Federal Power Act (FPA) and violates the Supremacy Clause, and is therefore

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

null and void. On October 11, 2013, the Federal district court issued an order ruling that the SOCAs are void, invalid and unenforceable, which order was affirmed by the U.S. Court of Appeals for the Third Circuit on September 11, 2014.

On November 26, 2014 and December 10, 2014, respectively, one of the generation companies and the NJBPU petitioned the U.S. Supreme Court to consider hearing an appeal of the Third Circuit decision. On April 19, 2016, the U.S. Supreme Court unanimously affirmed the Fourth Circuit decision, discussed above under MDPSC New Generation Contract Requirement, holding that the MDPSC's required contracts are illegal and unenforceable. On April 25, 2016, the U.S. Supreme Court ruled not to review the Third Circuit decision. This denial leaves the Third Circuit decision in place, with the same outcome as the Fourth Circuit decision.

ACE terminated one of the three SOCAs effective July 1, 2013 due to the occurrence of an event of default on the part of the generation company counterparty. ACE terminated the remaining two SOCAs effective November 19, 2013, in response to the October 2013 Federal district court decision.

**New York Regulatory Matters**

***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 New York Public Service Commission (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.

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. Because all regulatory approvals for the RSSA have now been received, Generation began recognizing revenue based on the final approved pricing contained in the RSSA. Generation also recognized a one-time revenue adjustment in April 2016 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 will be removed from Generation's results as a result of the noncontrolling interests in CENG.

The RSSA approved by the regulatory authorities has a term expiring on March 31, 2017, subject to possible extension in the event that RG&E needs additional time to complete transmission upgrades to address reliability concerns. In March 2016, RG&E notified Ginna that RG&E expects to complete the transmission upgrades prior to the RSSA expiration in March 2017 and will not need Ginna as an ongoing reliability solution after that date.

If Ginna does not plan to retire shortly after the expiration of the RSSA, Ginna is required to file a notice to that effect with the NYPSC no later than September 30, 2016. Under the terms of the RSSA, if Ginna continues to operate after June 14, 2017, Ginna would be required to make certain refund payments up to a maximum of \$20 million to RG&E related to capital expenditures.

The approved RSSA requires Ginna to continue operating through the RSSA term. There remains an increased risk that, for economic reasons, Ginna could be retired before the end of its operating license period in 2029 if an adequate regulatory or legislative solution is not adopted in New York. In the event the plant were to be retired before the current license term ends in 2029, Exelon's and Generation's results of operations could be adversely affected by the accelerated future decommissioning costs, severance costs, increased depreciation

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rates, and impairment charges, among other items. See Note 7-Early Nuclear Plant Retirements for further information regarding the impacts of a decision to early retire one or more nuclear plants.

**New York Clean Energy Standard (Exelon, Generation).** On August 1, 2016, the Clean Energy Standard (CES) was approved by the New York Public Service Commission (NYPSC), a component of which includes creation of a Tier 3 Zero Emission Credit (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 by the federal government. 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 CES initially identifies the three plants eligible for the ZEC program to include, for now, the FitzPatrick, Ginna, and Nine Mile Point nuclear facilities. The program specifically provides that Nine Mile Point Units 1 & 2 qualify jointly as a single facility and if either unit permanently ceases operations then both units will no longer qualify for ZEC payments for the remainder of the program. Additionally, the duration of the program beyond the first tranche is conditional upon a buyer purchasing the FitzPatrick facility and taking title prior to September 1, 2018. See Note 7 Early Nuclear Plant Retirements for additional information relative to Ginna and Nine Mile Point.

**Federal Regulatory Matters**

**Transmission Formula Rate (Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE).** ComEd's, BGE's, Pepco's, DPL's and ACE's transmission rates are each established based on a FERC-approved formula. ComEd, BGE, Pepco, DPL, and ACE are required to file an annual update to the FERC-approved formula on or before May 15, with the resulting rates effective on June 1 of the same year. The annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement in effect beginning June 1 of the prior year and actual costs incurred for that year. ComEd, BGE, Pepco, DPL, and ACE record regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement in effect and ComEd's, BGE's, Pepco's, DPL's and ACE's best estimate of the revenue requirement expected to be filed with the FERC for that year's reconciliation. The regulatory asset associated with transmission true-up is amortized to Operating revenues within their Consolidated Statements of Operations of Comprehensive Income as the associated amounts are recovered through rates.

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

	ComEd	BGE	2016 Pepco	DPL	ACE
<b>Annual Transmission Filings<sup>(a)</sup></b>					
Initial revenue requirement increase <sup>(b)</sup>	\$ 90	\$ 12	\$ 2	\$ 8	\$ 8
Annual reconciliation (decrease) increase	4	3	(10)	(10)	(14)
MAPP abandonment recovery decrease			(15)	(12)	
<b>Total revenue requirement increase (decrease)</b>	<b>\$ 94</b>	<b>\$ 15</b>	<b>\$ (23)</b>	<b>\$ (14)</b>	<b>\$ (6)</b>
Allowed return on rate base <sup>(c)</sup>	8.47%	8.09%	7.88%	7.21%	7.83%
Previously authorized allowed return on rate base <sup>(c)</sup>	8.61%	8.46%	8.36%	7.80%	8.51%
Allowed ROE <sup>(d)</sup>	11.50%	10.50%	10.5%	10.50%	10.50%

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- (a) All rates are effective June 2016.
- (b) For BGE, this excludes the increase in revenue requirement associated with dedicated facilities charges of \$13 million.
- (c) Refers to 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 ComEd and BGE's transmission formula rate filings see Note 3 Regulatory Matters of the Exelon 2015 Form 10-K. For additional information regarding Pepco, DPL and ACE's transmission formula rate filings see Note 7 Regulatory Matters of the PHI 2015 Form 10-K.

***PJM Transmission Rate Design and Operating Agreements (Exelon, Generation, ComEd, PECO, BGE, 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 an Offer of Settlement with FERC. Each state that is a party in this proceeding either signed, or will not oppose, the settlement. If the Settlement is approved, effective January 1, 2016, for the costs of the 500 kV facilities approved by the PJM Board on or after February 1, 2013, 50% will be socialized across PJM and 50% will be allocated according to an engineering formula that calculates the flows on the transmission facilities. 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 Generation's, ComEd's, PECO's, BGE's or PHI's results of operations, cash flows, and financial position. The Settlement is subject to approval by FERC. On July 5, 2016, a number of merchant transmission owners and load serving entities opposed the Settlement in whole or in part.

***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

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

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 August 7, 2015, US Fish and Wildlife Service of the US Department of the Interior (Interior) submitted its modified fishway prescription to FERC in the Conowingo licensing proceedings. On September 11, 2015, Exelon filed a request for an administrative hearing and proposed an alternative prescription to challenge Interior's preliminary prescription. On April 21, 2016, Exelon and Interior executed a Settlement Agreement resolving all issues between Exelon and Interior relating to fish passage at Conowingo. Accordingly, on April 22, 2016, Exelon withdrew its Request for a Trial-Type Hearing and Alternative Prescription. The financial impact of the Settlement Agreement is estimated to be \$3 million to \$7 million per year, on average, over the 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, 2016, \$26 million of direct costs associated with the Conowingo licensing effort have been capitalized. See Note 3 Regulatory Matters of the Exelon 2015 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.

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(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, 2016 and December 31, 2015. For additional information on the specific regulatory assets and liabilities, refer to Note 3 Regulatory Matters of the Exelon 2015 Form 10-K and Note 7 Regulatory Matters of the PHI 2015 Form 10-K.

June 30, 2016	Exelon	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
<b>Regulatory assets</b>								
Pension and other postretirement benefits <sup>(a)</sup>	\$ 4,160	\$	\$	\$	\$	\$	\$	\$
Deferred income taxes <sup>(b)</sup>	1,928	70	1,536	94	228	148	36	44
AMI programs <sup>(c)</sup>	712	156	56	240	260	174	86	
Under-recovered distribution service costs <sup>(d)</sup>	207	207						
Debt costs <sup>(e)</sup>	130	44	1	7	85	18	10	6
Fair value of long-term debt <sup>(f)</sup>	847				698			
Fair value of PHI's unamortized energy contracts <sup>(g)</sup>	1,350				1,350			
Severance	7			7				
Asset retirement obligations	117	74	22	20	1	1		
MGP remediation costs	290	262	27	1				
Under-recovered uncollectible accounts	54	54						
Renewable energy	226	221			5		1	4
Energy and transmission programs <sup>(h)(i)(j)(k)(l)</sup>	103	41		36	26		6	20
Deferred storm costs	43			1	42	17	5	20
Electric generation-related regulatory asset	15			15				
Rate stabilization deferral	54			54				
Energy efficiency and demand response programs	634		1	264	369	266	103	
Merger integration costs <sup>(m)(n)</sup>	23			11	12	9	3	
Under-recovered revenue decoupling <sup>(o)(p)</sup>	40			26	14	12	2	
COPCO acquisition adjustment	10				10		10	
Recoverable workers compensation and long-term disability	31				31	31		
Vacation accrual	47		21		26		15	11
Securitized stranded costs	169				169			169
CAP arrearage	7		7					
Removal costs	425				425	112	78	236
AEC <sup>(q)</sup>	7				7			
Other	44	7	13	5	16	10	3	5
<b>Total regulatory assets</b>	<b>11,680</b>	<b>1,136</b>	<b>1,684</b>	<b>781</b>	<b>3,774</b>	<b>798</b>	<b>358</b>	<b>515</b>
Less: current portion	1,559	213	48	261	730	129	63	97
<b>Total non-current regulatory assets</b>	<b>\$ 10,121</b>	<b>\$ 923</b>	<b>\$ 1,636</b>	<b>\$ 520</b>	<b>\$ 3,044</b>	<b>\$ 669</b>	<b>\$ 295</b>	<b>\$ 418</b>

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

June 30, 2016	Exelon	ComEd	PECO	BGE	<i>Successor</i> PHI	Pepco	DPL	ACE
<b>Regulatory liabilities</b>								
Other postretirement benefits	\$ 90	\$	\$	\$	\$	\$	\$	\$
Nuclear decommissioning	2,642	2,205	437					
Removal costs	1,648	1,330		172	146	20	126	
Deferred rent <sup>(s)</sup>	42				42			
Energy efficiency and demand response programs	134	97	37					
DLC program costs	9		9					
Electric distribution tax repairs	84		84					
Gas distribution tax repairs	24		24					
Energy and transmission programs <sup>(h)(i)(s)(j)(k)(l)</sup>	164	41	63	8	52	22	21	9
Over-recovered revenue decoupling <sup>(o)</sup>	3			3				
Other	52	4	3	14	32	9	8	14
<b>Total regulatory liabilities</b>	<b>4,892</b>	<b>3,677</b>	<b>657</b>	<b>197</b>	<b>272</b>	<b>51</b>	<b>155</b>	<b>23</b>
Less: current portion	503	153	128	60	101	27	53	21
<b>Total non-current regulatory liabilities</b>	<b>\$ 4,389</b>	<b>\$ 3,524</b>	<b>\$ 529</b>	<b>\$ 137</b>	<b>\$ 171</b>	<b>\$ 24</b>	<b>\$ 102</b>	<b>\$ 2</b>

December 31, 2015	Exelon	ComEd	PECO	BGE	<i>Predecessor</i> PHI	Pepco	DPL	ACE
<b>Regulatory assets</b>								
Pension and other postretirement benefits	\$ 3,156	\$	\$	\$	\$ 910	\$	\$	\$
Deferred income taxes	1,616	64	1,473	79	214	137	36	41
AMI programs <sup>(c)</sup>	399	140	63	196	267	180	87	
Under-recovered distribution service costs <sup>(d)</sup>	189	189						
Debt costs	47	46	1	8	36	19	10	7
Fair value of long-term debt <sup>(f)</sup>	162							
Severance	9			9				
Asset retirement obligations	108	67	22	19	1	1		
MGP remediation costs	286	255	30	1				
Under-recovered uncollectible accounts	52	52						
Renewable energy	247	247			6		1	5
Energy and transmission programs <sup>(h)(i)(s)(j)(k)(l)</sup>	84	43	1	40	33	9	11	13
Deferred storm costs	2			2	43	19	6	18
Electric generation-related regulatory asset	20			20				
Rate stabilization deferral	87			87				
Energy efficiency and demand response programs	279		1	278	401	289	111	1
Merger integration costs <sup>(m)</sup>	6			6				
Conservation voltage reduction	3			3				
Under-recovered revenue decoupling <sup>(o)(p)</sup>	30			30	14	10	4	
COPCO acquisition adjustment							13	
Workers compensation and long-term disability costs					31	31		
Vacation accrual	6		6		23		14	9
Securitized stranded costs					202			202
CAP arrearage	7		7					

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Removal costs					369	92	69	208
Other	29	10	13	3	32	14	9	8
Total regulatory assets	6,824	1,113	1,617	781	2,582	801	371	512
Less: current portion	759	218	34	267	305	140	72	98
Total non-current regulatory assets	\$ 6,065	\$ 895	\$ 1,583	\$ 514	\$ 2,277	\$ 661	\$ 299	\$ 414



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

December 31, 2015	Exelon	ComEd	PECO	BGE	<i>Predecessor</i> PHI	Pepco	DPL	ACE
<b>Regulatory liabilities</b>								
Other postretirement benefits	\$ 94	\$	\$	\$	\$	\$	\$	\$
Nuclear decommissioning	2,577	2,172	405					
Removal costs	1,527	1,332		195	150	21	129	
Energy efficiency and demand response programs	92	52	40		1			1
DLC program costs	9		9					
Electric distribution tax repairs	95		95					
Gas distribution tax repairs	28		28					
Energy and transmission programs <sup>(h)(i)(s)(j)(k)(l)</sup>	131	53	60	18	27	16	19	8
Over-recovered revenue decoupling <sup>(o)</sup>	1			1				
Other	16	5	2	8	35	7	12	16
<b>Total regulatory liabilities</b>	<b>4,570</b>	<b>3,614</b>	<b>639</b>	<b>222</b>	<b>213</b>	<b>44</b>	<b>160</b>	<b>25</b>
<b>Less: current portion</b>	<b>369</b>	<b>155</b>	<b>112</b>	<b>38</b>	<b>66</b>	<b>15</b>	<b>49</b>	<b>18</b>
<b>Total non-current regulatory liabilities</b>	<b>\$ 4,201</b>	<b>\$ 3,459</b>	<b>\$ 527</b>	<b>\$ 184</b>	<b>\$ 147</b>	<b>\$ 29</b>	<b>\$ 111</b>	<b>\$ 7</b>

- (a) As of June 30, 2016, the pension and other postretirement benefits regulatory asset at Exelon includes regulatory assets of \$1,087 million established at the date 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.
- (b) As of June 30, 2016, includes transmission-related regulatory assets that require FERC approval separate from the transmission formula rate of \$19 million, \$30 million, \$38 million, \$19 million and \$17 million for ComEd, BGE, Pepco, DPL and ACE, respectively. As of December 31, 2015, includes transmission-related regulatory assets that require FERC approval separate from the transmission formula rate of \$15 million, \$16 million, \$36 million, \$18 million and \$15 million for ComEd, BGE, Pepco, DPL and ACE, respectively.
- (c) Represents AMI costs associated with the installation of smart meters and the early retirement of legacy meters throughout the service territories for ComEd, PECO, BGE, Pepco and DPL. An AMI program has not been approved by the NJBPU for ACE in New Jersey. DPL and Pepco have received approval for recovery of deferred AMI program costs from the DCPSC and DPSC in the Delaware and DC service territories, and have requested recovery in pending distribution rate cases with the MDPSC for the Maryland service territories. As of June 30, 2016, the portion of deferred AMI program costs pending approval from the MDPSC is \$32 million for BGE, \$139 million for Pepco and \$43 million for DPL, of which \$78 million for Pepco and \$14 million for DPL relates to retired legacy meters which are not earning a return and \$2 million of post-test year costs for Pepco which are not earning a return.
- (d) As of June 30, 2016, ComEd's regulatory asset of \$207 million was comprised of \$163 million for the 2014-2016 annual reconciliations and \$44 million related to significant one-time events including \$28 million of deferred storm costs, \$11 million of Constellation and PHI merger and integration related costs and \$5 million of smart meter related costs. As of December 31, 2015, ComEd's regulatory asset of \$189 million was comprised of \$142 million for the 2014 and 2015 annual reconciliations and \$47 million related to significant one-time events, including \$36 million of deferred storm costs and \$11 million of Constellation merger and integration related costs. See Note 4 Merger, Acquisitions, and Dispositions of the Exelon 2015 Form 10-K for further information.
- (e) Includes at Exelon and PHI the regulatory asset recorded at PHI for debt costs that are recoverable through the ratemaking process at Pepco, DPL, and ACE which were eliminated at Exelon and PHI as part of acquisition accounting.
- (f) Includes the unamortized regulatory assets recorded for the difference between carrying value and fair value of long-term debt of BGE as of the Constellation merger date and at Exelon and PHI for the difference between carrying value and fair value of long-term debt of Pepco, DPL and ACE as of the PHI Merger date.
- (g) Represents the regulatory asset recorded at Exelon and PHI offsetting the fair value adjustments related to Pepco's, DPL's and ACE's electricity and natural gas energy supply contracts recorded at PHI as of the PHI Merger date. Pepco, DPL and ACE are allowed full

recovery of the costs of these contracts through their respective rate making processes.

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- (h) As of June 30, 2016, ComEd's regulatory asset of \$41 million included \$4 million related to under-recovered energy costs, \$30 million associated with transmission costs recoverable through its FERC approved formula rate, and \$7 million of Constellation merger and integration costs to be recovered upon FERC approval. As of June 30, 2016, ComEd's regulatory liability of \$41 million included \$13 million related to over-recovered energy costs and \$28 million associated with revenues received for renewable energy requirements. As of December 31, 2015, ComEd's regulatory asset of \$43 million included \$5 million related to under-recovered energy costs, \$31 million associated with transmission costs recoverable through its FERC approved formula rate, and \$7 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2015, ComEd's regulatory liability of \$53 million included \$29 million related to over-recovered energy costs and \$24 million associated with revenues received for renewable energy requirements.
- (i) As of June 30, 2016, BGE's regulatory asset of \$36 million included \$6 million of costs associated with transmission costs recoverable through its FERC approved formula rate, \$29 million related to under-recovered electric energy costs, and \$1 million of abandonment costs to be recovered upon FERC approval. As of June 30, 2016, BGE's regulatory liability of \$8 million related to \$8 million of over-recovered natural gas costs. As of December 31, 2015, BGE's regulatory asset of \$40 million included \$12 million of costs associated with transmission costs recoverable through its FERC approved formula rate and \$28 million related to under-recovered electric energy costs. As of December 31, 2015, BGE's regulatory liability of \$18 million related to \$14 million of over-recovered transmission costs and \$5 million of over-recovered natural gas costs, offset by \$1 million of abandonment costs to be recovered upon FERC approval.
- (j) As of June 30, 2016, Pepco's regulatory liability of \$22 million included \$12 million of over-recovered transmission costs and \$10 million of over-recovered electric energy costs. As of December 31, 2015, Pepco's regulatory asset of \$9 million included \$5 million of transmission costs recoverable through its FERC approved formula rate and \$4 million of recoverable abandonment costs. As of December 31, 2015, Pepco's regulatory liability of \$16 million included \$14 million of over-recovered transmission costs and \$2 million of over-recovered electric energy costs.
- (k) As of June 30, 2016, DPL's regulatory asset of \$6 million related to under-recovered electric energy costs. As of June 30, 2016, DPL's regulatory liability of \$21 million included \$4 million related to over-recovered natural gas costs under the GCR mechanism, \$10 million of over-recovered electric energy costs, and \$7 million of over-recovered transmission costs. As of December 31, 2015, DPL's regulatory asset of \$11 million included \$7 million of transmission costs recoverable through its FERC approved formula rate, \$3 million of recoverable abandonment costs, and \$1 million of under-recovered electric energy costs. As of December 31, 2015, DPL's regulatory liability of \$19 million included \$4 million related to the over-recovered natural gas costs under the GCR mechanism, \$4 million of over-recovered electric energy costs, and \$11 million of over-recovered transmission costs.
- (l) As of June 30, 2016, ACE's regulatory asset of \$20 million related to of under-recovered electric energy costs. As of June 30, 2016, ACE's regulatory liability of \$9 million related to over-recovered transmission costs. As of December 31, 2015, ACE's regulatory asset of \$13 million included \$2 million of transmission costs recoverable through its FERC approved formula rate and \$11 million of under-recovered electric energy costs. As of December 31, 2015, ACE's regulatory liability of \$8 million related to over-recovered transmission costs.
- (m) As of June 30, 2016, BGE's regulatory asset of \$11 million included \$6 million of previously incurred PHI acquisition costs as authorized by the June 2016 rate case order.
- (n) Represents previously incurred PHI acquisition costs expected to be recovered in distribution rates in the Maryland service territories of Pepco and DPL.
- (o) Represents the electric and natural gas distribution costs recoverable from customers under BGE's decoupling mechanism. As of June 30, 2016, BGE had a regulatory asset of \$26 million related to under-recovered electric revenue decoupling and a regulatory liability of \$3 million related to over-recovered natural gas revenue decoupling. As of December 31, 2015, BGE had a regulatory asset of \$30 million related to under-recovered electric revenue decoupling and a regulatory liability of \$1 million related to over-recovered natural gas revenue decoupling.
- (p) Represents the electric distribution costs recoverable from customers under Pepco's Maryland and District of Columbia decoupling mechanisms and DPL's Maryland decoupling mechanism.
- (q) Represents the regulatory asset recorded at Exelon and PHI for the difference between the carrying value and fair value of alternative energy credits at Pepco, DPL and ACE recorded at Exelon and PHI that are recoverable through the rate making process.
- (r) Represents the regulatory liability recorded at Exelon and PHI for deferred rent related to a lease that is recoverable through the ratemaking process at Pepco, DPL and ACE.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

- (s) As of June 30, 2016, PECO's regulatory liability of \$63 million included \$31 million related to over-recovered costs under the DSP program, \$23 million related to the over-recovered natural gas costs under the PGC, \$7 million related to over-recovered non-bypassable transmission service charges and \$2 million related to over-recovered electric transmission costs. As of December 31, 2015, PECO's regulatory asset of \$1 million related to under-recovered non-bypassable transmission service charges. As of December 31, 2015, PECO's regulatory liability of \$60 million included \$35 million related to over-recovered costs under the DSP program, \$22 million related to the over-recovered natural gas costs under the PGC and \$3 million related to the over-recovered electric transmission costs.

**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 and ACE are required to purchase receivables at face value and are permitted to recover uncollectible accounts expense from customers through distribution rates. 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, 2016 and December 31, 2015.

As of June 30, 2016	Exelon	ComEd	PECO	BGE	Successor			
					PHI	Pepco	DPL	ACE
Purchased receivables <sup>(c)</sup>	\$ 327	\$ 103	\$ 72	\$ 54	\$ 98	\$ 69	\$ 10	\$ 19
Allowance for uncollectible accounts <sup>(a)</sup>	(31)	(14)	(6)	(5)	(6)	(4)		(2)
Purchased receivables, net	\$ 296	\$ 89	\$ 66	\$ 49	\$ 92	\$ 65	\$ 10	\$ 17

As of December 31, 2015	Exelon	ComEd	PECO	BGE	Predecessor			
					PHI	Pepco	DPL	ACE
Purchased receivables <sup>(b)(c)</sup>	\$ 229	\$ 103	\$ 67	\$ 59	\$ 100	\$ 70	\$ 11	\$ 19
Allowance for uncollectible accounts <sup>(a)</sup>	(31)	(16)	(7)	(8)	(6)	(4)		(2)
Purchased receivables, net	\$ 198	\$ 87	\$ 60	\$ 51	\$ 94	\$ 66	\$ 11	\$ 17

- (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) PECO's natural gas POR program became effective on January 1, 2012 and included a 1% discount on purchased receivables in order to recover the implementation costs of the program. The implementation costs were fully recovered and the 1% discount was reset to 0%, effective July 2015.
- (c) Pepco's electric POR program in Maryland included a discount on purchased receivables ranging from 0% to 2% depending on customer class, and Pepco's electric POR program in the District of Columbia included a discount on purchased receivables ranging from 0% to 6% depending on customer class. DPL's electric POR program in Maryland included a discount on purchased receivables ranging from 0% to 1% depending on customer class.

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

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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 10 Debt and Credit Agreements) and continued declines in both production volumes and

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

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, see Note 10 Debt and Credit Agreements for additional information. As a result, the Upstream assets and liabilities were classified as held for sale on Exelon's and Generation's Consolidated Balance Sheets at June 30, 2016. See Note 4 Mergers, Acquisitions and Dispositions for additional information. Further declines in commodity prices or further developments with Generation's intended use or disposition of the assets could potentially result in future impairments of the Upstream assets. The fair value analysis was primarily based on the income approach using significant unobservable inputs (Level 3) including commodity prices and production volumes, projected capital and maintenance expenditures and discount rates.

Generation evaluates long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. 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 retirement announcements of the Quad Cities and Clinton nuclear plants 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.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****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 final rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules.

In 2015, Generation identified the Quad Cities, Clinton and Ginna nuclear plants as having the greatest risk of early retirement based on economic valuation and other factors. At that time, Exelon and Generation deferred retirement decisions on Clinton and Quad Cities until 2016 in order to participate in the 2016-2017 MISO primary reliability auction and the 2019-2020 PJM capacity auctions held in April and May 2016, respectively, as well as to provide Illinois policy makers with additional time to consider needed reforms and for MISO to consider market design changes to ensure long-term power system reliability in southern Illinois.

In April 2016, Clinton cleared the MISO primary reliability auction as a price taker for the 2016-2017 planning year. The resulting capacity price is insufficient to cover cash operating costs and a risk-adjusted rate of return to shareholders. In May 2016, Quad Cities did not clear in the PJM capacity auction for the 2019-2020 planning year and will not receive capacity revenue for that period.

Based on these capacity auction results, and given the lack of progress on Illinois energy legislation and MISO market reforms, on June 2, 2016 Generation announced it will move forward to shut down the Clinton and Quad Cities nuclear plants on June 1, 2017 and June 1, 2018, respectively. The current Nuclear Regulatory Commission (NRC) licenses for Clinton and Quad Cities expire in 2026 and 2032, respectively. Generation is proceeding with the market and regulatory notifications that must be made to shut down the plants, including notification to the NRC on June 20, 2016, and filing of a deactivation notice with PJM for Quad Cities on July 6, 2016. Generation will formally notify MISO of its plans to close Clinton later this year.

In the second quarter of 2016, as a result of the plant retirement decision for Clinton and Quad Cities, Exelon and Generation recognized one-time charges in Operating and maintenance expense of \$141 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 Clinton and Quad Cities 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 2016 results include an incremental \$110 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 Clinton and Quad Cities.

The Three Mile Island (TMI) nuclear plant also did not clear in the May 2016 PJM capacity auction for the 2019-2020 planning year and will not receive capacity revenue for that period. This is the second consecutive year that TMI failed to clear the capacity auction. Although the plant is committed to operate through May 2018, the plant faces continued economic challenges and Exelon and Generation are exploring all options to return it to profitability. While a portion of the Byron nuclear plant's capacity did not clear the PJM 2019-2020 planning year capacity auction, the plant is committed to run through May 2020. The company's other nuclear plants in PJM cleared in the auction, except Oyster Creek, which did not participate in the auction given Exelon's and Generation's previous commitment to cease operation of the Oyster Creek nuclear plant by the end of 2019.

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

In New York, the Ginna and Nine Mile Point nuclear plants continue to face 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, and 2046 for Nine Mile Point Unit 2). On August 1, 2016, the New York Public Service Commission (NYPSC) issued an order adopting the Clean Energy Standard (CES), which would provide payments to Ginna and Nine Mile Point for the environmental attributes of their production. Subject to Ginna and Nine Mile Point entering into a satisfactory contract with the New York State Energy Research & Development Agency (NYSERDA), as required under the CES, and subject to any potential administrative or legal challenges, the CES will allow Ginna and Nine Mile Point to continue to operate at least through the life of the program (March 31, 2029). The approved RSSA currently requires Ginna to continue operating through the RSSA term expiring in March 2017. If Ginna does not plan to retire shortly after the expiration of the RSSA, Ginna is required to file a notice to that effect with the NYPSC no later than September 30, 2016. Refer to Note 5 Regulatory Matters for additional discussion on the Ginna RSSA and the New York CES.

The following table provides the balance sheet amounts as of June 30, 2016 for significant assets and liabilities associated with the three nuclear plants currently considered by management to be at the greatest risk of early retirement due to current economic valuations and other factors.

(in millions)	TMI	Ginna	NMP
<b>Asset Balances</b>			
Materials and supplies inventory	\$ 38	\$ 30	\$ 69
Nuclear fuel inventory, net	104	47	235
Completed plant, net	968	125	1,137
Construction work in progress	35	12	70
<b>Liability Balances</b>			
Asset retirement obligation	(485)	(659)	(770)
NRC License Renewal Term	2034	2029	2029 (unit 1) 2046 (unit 2)

The precise timing of an early retirement date for any of these plants, 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 obligations, where applicable, and just prior to its next scheduled nuclear refueling outage.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

(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, trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) and preferred stock as of June 30, 2016 and December 31, 2015:

*Exelon*

	Carrying Amount	June 30, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 954	\$ 3	\$ 951	\$	\$ 954
Long-term debt (including amounts due within one year) <sup>(a)</sup>	34,234	1,135	33,863	2,176	37,174
Long-term debt to financing trusts <sup>(b)</sup>	641			689	689
SNF obligation	1,023		835		835

	Carrying Amount	December 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 536	\$ 3	\$ 533	\$	\$ 536
Long-term debt (including amounts due within one year) <sup>(a)</sup>	25,145	931	23,644	1,349	25,924
Long-term debt to financing trusts <sup>(b)</sup>	641			673	673
SNF obligation	1,021		818		818

*Generation*

	Carrying Amount	June 30, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 208	\$	\$ 208	\$	\$ 208
Long-term debt (including amounts due within one year) <sup>(a)</sup>	9,066		7,953	1,577	9,530
SNF obligation	1,023		835		835

	Carrying Amount	December 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 29	\$	\$ 29	\$	\$ 29
Long-term debt (including amounts due within one year) <sup>(a)</sup>	8,959		7,767	1,349	9,116
SNF obligation	1,021		818		818

*ComEd*

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	Carrying Amount	June 30, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 35	\$	\$ 35	\$	\$ 35
Long-term debt (including amounts due within one year) <sup>(a)</sup>	7,695		8,832		8,832
Long-term debt to financing trusts <sup>(b)</sup>	205			209	209

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

	Carrying Amount	December 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 294	\$	\$ 294	\$	\$ 294
Long-term debt (including amounts due within one year) <sup>(a)</sup>	6,509		7,069		7,069
Long-term debt to financing trusts <sup>(b)</sup>	205			213	213

*PECO*

	Carrying Amount	June 30, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Long-term debt (including amounts due within one year) <sup>(a)</sup>	\$ 2,581	\$	\$ 3,002	\$	\$ 3,002
Long-term debt to financing trusts	184			205	205

	Carrying Amount	December 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
Long-term debt (including amounts due within one year) <sup>(a)</sup>	\$ 2,580	\$	\$ 2,786	\$	\$ 2,786
Long-term debt to financing trusts	184			195	195

*BGE*

	Carrying Amount	June 30, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 211	\$ 3	\$ 208	\$	\$ 211
Long-term debt (including amounts due within one year) <sup>(a)</sup>	1,820		2,136		2,136
Long-term debt to financing trusts <sup>(b)</sup>	252			275	275

	Carrying Amount	December 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 213	\$ 3	\$ 210	\$	\$ 213
Long-term debt (including amounts due within one year) <sup>(a)</sup>	1,858		2,044		2,044
Long-term debt to financing trusts <sup>(b)</sup>	252			264	264

*PHI*

	Carrying Amount	June 30, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 500	\$	\$ 500	\$	\$ 500
Long-term debt (including amounts due within one year)	6,073		5,752	599	6,351

*Successor*



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

	Carrying Amount	December 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
<i>Predecessor</i>					
Short-term liabilities	\$ 958	\$	\$ 958	\$	\$ 958
Long-term debt (including amounts due within one year) <sup>(a)</sup>	5,279		5,231	586	5,817
Preferred stock	183			183	183

*Pepco*

	Carrying Amount	June 30, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Long-term debt (including amounts due within one year) <sup>(a)</sup>	\$ 2,349	\$	\$ 3,028	\$ 2	\$ 3,030

	Carrying Amount	December 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 64	\$	\$ 64	\$	\$ 64
Long-term debt (including amounts due within one year) <sup>(a)</sup>	2,351		2,673		2,673

*DPL*

	Carrying Amount	June 30, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Long-term debt (including amounts due within one year) <sup>(a)</sup>	\$ 1,265	\$	\$ 1,279	\$ 102	\$ 1,381

	Carrying Amount	December 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 105	\$	\$ 105	\$	\$ 105
Long-term debt (including amounts due within one year) <sup>(a)</sup>	1,265		1,185	103	1,288

*ACE*

	Carrying Amount	June 30, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Long-term debt (including amounts due within one year) <sup>(a)</sup>	\$ 1,180	\$	\$ 1,083	\$ 301	\$ 1,384

	Carrying Amount	December 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 5	\$	\$ 5	\$	\$ 5

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Long-term debt (including amounts due within one year) <sup>(a)</sup>	1,201	1,044	280	1,324
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(a) Includes unamortized debt issuance costs of \$200 million, \$69 million, \$48 million, \$14 million, \$8 million, \$30 million, \$10 million, and \$6 million for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE, respectively, as of

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

June 30, 2016. Includes unamortized debt issuance costs of \$180 million, \$70 million, \$38 million, \$15 million, \$9 million, \$49 million, \$31 million, \$10 million, and \$6 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, as of December 31, 2015.

(b) Includes unamortized debt issuance costs of \$7 million, \$1 million, and \$6 million for Exelon, ComEd and BGE, respectively, as of June 30, 2016 and December 31, 2015.

*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 electric 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 PHI'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 project 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 project 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 estimated to be settled in 2025 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 2025.

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

*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.

*Preferred Stock.* The fair value of these securities is determined based on the carrying value of the shares per the Subscription Agreement between PHI and Exelon. See Note 16 Mezzanine Equity for further details.

***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 significant transfers between Level 1 and Level 2 during the six months ended June 30, 2016 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. See Note 2 New Accounting Pronouncements for additional information.



**Table of Contents****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, 2016 and December 31, 2015:

As of June 30, 2016	Generation					Exelon				
	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
<b>Assets</b>										
Cash equivalents <sup>(a)</sup>	\$ 42	\$	\$	\$	\$ 42	\$ 1,311	\$	\$	\$	\$ 1,311
NDT fund investments										
Cash equivalents <sup>(b)</sup>	381	12			393	381	12			393
Equities	3,205	215	1	1,908	5,329	3,205	215	1	1,908	5,329
Fixed income										
Corporate debt		1,910	249		2,159		1,910	249		2,159
U.S. Treasury and agencies	1,452	29			1,481	1,452	29			1,481
Foreign governments		44			44		44			44
State and municipal debt		285			285		285			285
Other <sup>(c)</sup>		60		399	459		60		399	459
Fixed income subtotal	1,452	2,328	249	399	4,428	1,452	2,328	249	399	4,428
Middle market lending										
Private equity			465	124	465			465	124	465
Real estate				46	46				46	46
NDT fund investments subtotal <sup>(d)</sup>	5,038	2,555	715	2,477	10,785	5,038	2,555	715	2,477	10,785
Pledged assets for Zion Station decommissioning										
Cash equivalents	15				15	15				15
Equities		6			6		6			6
Fixed income										
U.S. Treasury and agencies	23	2			25	23	2			25
Corporate debt		9			9		9			9
Fixed income subtotal	23	11			34	23	11			34
Middle market lending			25	81	106			25	81	106
Pledged assets for Zion Station decommissioning subtotal <sup>(e)</sup>	38	17	25	81	161	38	17	25	81	161
Rabbi trust investments										
Cash equivalents	8				8	81				81
Mutual funds	18				18	49				49
Fixed income										
Life insurance contracts		17			17		63	20		83
Rabbi trust investments subtotal	26	17			43	130	77	20		227

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Commodity derivative assets										
Economic hedges	1,342	3,087	1,506		5,935	1,343	3,087	1,506		5,936
Proprietary trading	25	71	31		127	25	71	31		127
Effect of netting and allocation of collateral <sup>(f)</sup>	(1,308)	(2,733)	(779)		(4,820)	(1,309)	(2,733)	(779)		(4,821)
Commodity derivative assets subtotal	59	425	758		1,242	59	425	758		1,242
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments										
Economic hedges		28			28		28			28
Proprietary trading	10	1			11	10	1			11
Effect of netting and allocation of collateral	(7)	(16)			(23)	(7)	(16)			(23)
Interest rate and foreign currency derivative assets subtotal	3	13			16	3	60			63
Other investments			37		37			37		37
<b>Total assets</b>	<b>5,206</b>	<b>3,027</b>	<b>1,535</b>	<b>2,558</b>	<b>12,326</b>	<b>6,579</b>	<b>3,134</b>	<b>1,555</b>	<b>2,558</b>	<b>13,826</b>

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

As of June 30, 2016	Generation					Exelon				
	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
<b>Liabilities</b>										
Commodity derivative liabilities										
Economic hedges	(1,456)	(3,089)	(1,013)		(5,558)	(1,456)	(3,089)	(1,234)		(5,779)
Proprietary trading	(24)	(73)	(34)		(131)	(24)	(73)	(34)		(131)
Effect of netting and allocation of collateral <sup>(f)</sup>	1,431	3,012	898		5,341	1,431	3,012	898		5,341
Commodity derivative liabilities subtotal	(49)	(150)	(149)		(348)	(49)	(150)	(370)		(569)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments		(21)			(21)		(23)			(23)
Economic hedges		(19)			(19)		(19)			(19)
Proprietary trading	(9)				(9)	(9)				(9)
Effect of netting and allocation of collateral	10	16			26	10	16			26
Interest rate and foreign currency derivative liabilities subtotal	1	(24)			(23)	1	(26)			(25)
Deferred compensation obligation		(30)			(30)		(127)			(127)
<b>Total liabilities</b>	(48)	(204)	(149)		(401)	(48)	(303)	(370)		(721)
<b>Total net assets</b>	\$ 5,158	\$ 2,823	\$ 1,386	\$ 2,558	\$ 11,925	\$ 6,531	\$ 2,831	\$ 1,185	\$ 2,558	\$ 13,105

As of December 31, 2015	Generation					Exelon				
	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
<b>Assets</b>										
Cash equivalents <sup>(a)</sup>	\$ 104	\$	\$	\$	\$ 104	\$ 5,766	\$	\$	\$	\$ 5,766
NDT fund investments										
Cash equivalents <sup>(b)</sup>	219	92			311	219	92			311
Equities	3,008			1,894	4,902	3,008			1,894	4,902
Fixed income										
Corporate debt		1,824	242		2,066		1,824	242		2,066
U.S. Treasury and agencies	1,323	15			1,338	1,323	15			1,338
Foreign governments		61			61		61			61
State and municipal debt		326			326		326			326
Other <sup>(c)</sup>		147		390	537		147		390	537
Fixed income subtotal	1,323	2,373	242	390	4,328	1,323	2,373	242	390	4,328
Middle market lending										
Private equity			428		428			428		428
Real estate				125	125				125	125
Other				35	35				35	35
				216	216				216	216

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NDT fund investments subtotal <sup>(d)</sup>	4,550	2,465	670	2,660	10,345	4,550	2,465	670	2,660	10,345
Pledged assets for Zion Station decommissioning										
Cash equivalents		17			17		17			17
Equities	1	5			6	1	5			6
Fixed income										
U.S. Treasury and agencies	6	2			8	6	2			8
Corporate debt		46			46		46			46
Other		1			1		1			1
Fixed income subtotal	6	49			55	6	49			55
Middle market lending			22	105	127			22	105	127
Pledged assets for Zion Station decommissioning subtotal <sup>(e)</sup>										
	7	71	22	105	205	7	71	22	105	205

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

As of December 31, 2015	Generation				Total	Exelon				
	Level 1	Level 2	Level 3	Not subject to leveling		Level 1	Level 2	Level 3	Not subject to leveling	
<b>Rabbi trust investments</b>										
Mutual funds	17				17	48				48
Life insurance contracts		13			13		36			36
<b>Rabbi trust investments subtotal</b>	<b>17</b>	<b>13</b>			<b>30</b>	<b>48</b>	<b>36</b>			<b>84</b>
<b>Commodity derivative assets</b>										
Economic hedges	1,922	3,467	1,707		7,096	1,922	3,467	1,707		7,096
Proprietary trading	36	64	30		130	36	64	30		130
Effect of netting and allocation of collateral <sup>(f)</sup>	(1,964)	(2,629)	(564)		(5,157)	(1,964)	(2,629)	(564)		(5,157)
<b>Commodity derivative assets subtotal</b>	<b>(6)</b>	<b>902</b>	<b>1,173</b>		<b>2,069</b>	<b>(6)</b>	<b>902</b>	<b>1,173</b>		<b>2,069</b>
<b>Interest rate and foreign currency derivative assets</b>										
Derivatives designated as hedging instruments							25			25
Economic hedges		20			20		20			20
Proprietary trading	10	5			15	10	5			15
Effect of netting and allocation of collateral	(3)	(3)			(6)	(3)	(3)			(6)
<b>Interest rate and foreign currency derivative assets subtotal</b>	<b>7</b>	<b>22</b>			<b>29</b>	<b>7</b>	<b>47</b>			<b>54</b>
<b>Other investments</b>			33		33			33		33
<b>Total assets</b>	<b>4,679</b>	<b>3,473</b>	<b>1,898</b>	<b>2,765</b>	<b>12,815</b>	<b>10,372</b>	<b>3,521</b>	<b>1,898</b>	<b>2,765</b>	<b>18,556</b>
<b>Liabilities</b>										
<b>Commodity derivative liabilities</b>										
Economic hedges	(2,382)	(3,348)	(850)		(6,580)	(2,382)	(3,348)	(1,097)		(6,827)
Proprietary trading	(33)	(57)	(37)		(127)	(33)	(57)	(37)		(127)
Effect of netting and allocation of collateral <sup>(f)</sup>	2,440	3,186	765		6,391	2,440	3,186	765		6,391
<b>Commodity derivative liabilities subtotal</b>	<b>25</b>	<b>(219)</b>	<b>(122)</b>		<b>(316)</b>	<b>25</b>	<b>(219)</b>	<b>(369)</b>		<b>(563)</b>
<b>Interest rate and foreign currency derivative liabilities</b>										
Derivatives designated as hedging instruments		(16)			(16)		(16)			(16)
Economic hedges		(3)			(3)		(3)			(3)
Proprietary trading	(12)				(12)	(12)				(12)
Effect of netting and allocation of collateral	12	3			15	12	3			15
<b>Interest rate and foreign currency derivative liabilities subtotal</b>		<b>(16)</b>			<b>(16)</b>		<b>(16)</b>			<b>(16)</b>
<b>Deferred compensation obligation</b>		(30)			(30)		(99)			(99)
<b>Total liabilities</b>	<b>25</b>	<b>(265)</b>	<b>(122)</b>		<b>(362)</b>	<b>25</b>	<b>(334)</b>	<b>(369)</b>		<b>(678)</b>



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

- (d) Excludes net liabilities of \$(48) million and \$(3) million at June 30, 2016 and December 31, 2015, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.
- (e) Excludes net assets of less than \$1 million and \$1 million at June 30, 2016 and December 31, 2015, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
- (f) Collateral posted to/(received) from counterparties totaled \$123 million, \$279 million and \$119 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of June 30, 2016. Collateral posted (received) from counterparties, net of collateral paid to counterparties, totaled \$476 million, \$557 million and \$201 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2015.

*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, 2016 and December 31, 2015:

As of June 30, 2016	ComEd				PECO				BGE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>												
Cash equivalents <sup>(a)</sup>	\$ 700	\$	\$	\$ 700	\$ 184	\$	\$	\$ 184	\$ 20	\$	\$	\$ 20
Rabbi trust investments												
Mutual funds					7			7	4			4
Life insurance contracts						11		11				
Rabbi trust investments subtotal					7	11		18	4			4
<b>Total assets</b>	<b>700</b>			<b>700</b>	<b>191</b>	<b>11</b>		<b>202</b>	<b>24</b>			<b>24</b>
<b>Liabilities</b>												
Deferred compensation obligation		(8)		(8)		(10)		(10)		(4)		(4)
Mark-to-market derivative liabilities <sup>(b)</sup>			(221)	(221)								
<b>Total liabilities</b>		<b>(8)</b>	<b>(221)</b>	<b>(229)</b>		<b>(10)</b>		<b>(10)</b>		<b>(4)</b>		<b>(4)</b>
<b>Total net assets (liabilities)</b>	<b>\$ 700</b>	<b>\$ (8)</b>	<b>\$ (221)</b>	<b>\$ 471</b>	<b>\$ 191</b>	<b>\$ 1</b>	<b>\$</b>	<b>\$ 192</b>	<b>\$ 24</b>	<b>\$ (4)</b>	<b>\$</b>	<b>\$ 20</b>

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

As of December 31, 2015	ComEd				PECO				BGE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>												
Cash equivalents	\$ 29	\$	\$	\$ 29	\$ 271	\$	\$	\$ 271	\$ 25	\$	\$	\$ 25
Rabbi trust investments												
Mutual funds					8			8	4			4
Life insurance contracts						12		12				
Rabbi trust investments subtotal					8	12		20	4			4
<b>Total assets</b>	<b>29</b>			<b>29</b>	<b>279</b>	<b>12</b>		<b>291</b>	<b>29</b>			<b>29</b>
<b>Liabilities</b>												
Deferred compensation obligation		(8)		(8)		(12)		(12)		(4)		(4)
Mark-to-market derivative liabilities <sup>(b)</sup>			(247)	(247)								
<b>Total liabilities</b>		<b>(8)</b>	<b>(247)</b>	<b>(255)</b>		<b>(12)</b>		<b>(12)</b>		<b>(4)</b>		<b>(4)</b>
<b>Total net assets (liabilities)</b>	<b>\$ 29</b>	<b>\$ (8)</b>	<b>\$ (247)</b>	<b>\$ (226)</b>	<b>\$ 279</b>	<b>\$</b>	<b>\$</b>	<b>\$ 279</b>	<b>\$ 29</b>	<b>\$ (4)</b>	<b>\$</b>	<b>\$ 25</b>

(a) ComEd excludes cash of \$36 million and \$38 million at June 30, 2016 and December 31, 2015 and restricted cash of \$2 million and \$2 million at June 30, 2016 and December 31, 2015. PECO excludes cash of \$22 million and \$27 million at June 30, 2016 and December 31, 2015. BGE excludes cash of \$5 million and \$6 million at June 30, 2016 and December 31, 2015 and restricted cash of \$2 million and \$2 million at June 30, 2016 and December 31, 2015 and includes long term restricted cash of \$3 million at June 30, 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 \$18 million and \$203 million, respectively, at June 30, 2016, and \$23 million and \$224 million, respectively, at December 31, 2015, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.



**Table of Contents****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, 2016 and December 31, 2015:

PHI	Level 1	Successor As of June 30, 2016			Total	Predecessor As of December 31, 2015			Total
		Level 2	Level 3	Level 1		Level 2	Level 3		
<b>Assets</b>									
Cash equivalents <sup>(a)</sup>	\$ 344	\$	\$	\$ 344	\$ 42	\$	\$	\$ 42	
Mark-to-market derivative assets <sup>(b)(c)</sup>	1			1			18	18	
Effect of netting and allocation of collateral	(1)			(1)					
Mark-to-market derivative assets subtotal							18	18	
Rabbi trust investments									
Cash equivalents	73			73	12			12	
Fixed income		14		14		15		15	
Life insurance contracts		22	20	42		27	19	46	
Rabbi trust investments subtotal	73	36	20	129	12	42	19	73	
<b>Total assets</b>	<b>417</b>	<b>36</b>	<b>20</b>	<b>473</b>	<b>54</b>	<b>42</b>	<b>37</b>	<b>133</b>	
<b>Liabilities</b>									
Deferred compensation obligation		(28)		(28)		(30)		(30)	
Mark-to-market derivative liabilities <sup>(b)</sup>					(2)			(2)	
Effect of netting and allocation of collateral					2			2	
Mark-to-market derivative liabilities subtotal									
<b>Total liabilities</b>		<b>(28)</b>		<b>(28)</b>		<b>(30)</b>		<b>(30)</b>	
<b>Total net assets</b>	<b>\$ 417</b>	<b>\$ 8</b>	<b>\$ 20</b>	<b>\$ 445</b>	<b>\$ 54</b>	<b>\$ 12</b>	<b>\$ 37</b>	<b>\$ 103</b>	

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

As of June 30, 2016	Pepco				DPL				ACE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>												
Cash equivalents <sup>(a)</sup>	\$ 155	\$	\$	\$ 155	\$ 12	\$	\$	\$ 12	\$ 176	\$	\$	\$ 176
Mark-to-market derivative assets <sup>(b)</sup>					1			1				
Effect of netting and allocation of collateral					(1)			(1)				
<b>Mark-to-market derivative assets subtotal</b>												
<b>Rabbi trust investments</b>												
Cash equivalents	43			43								
Fixed income		14		14								
Life insurance contracts		22	20	42								
<b>Rabbi trust investments subtotal</b>	43	36	20	99								
<b>Total assets</b>	198	36	20	254	12			12	176			176
<b>Liabilities</b>												
Deferred compensation obligation		(5)		(5)		(1)		(1)				
<b>Total liabilities</b>		(5)		(5)		(1)		(1)				
<b>Total net assets (liabilities)</b>	\$ 198	\$ 31	\$ 20	\$ 249	\$ 12	\$ (1)	\$	\$ 11	\$ 176	\$	\$	\$ 176

As of December 31, 2015	Pepco				DPL				ACE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>												
Cash equivalents	\$ 2	\$	\$	\$ 2	\$	\$	\$	\$	\$ 30	\$	\$	\$ 30
<b>Rabbi trust investments</b>												
Cash equivalents	11			11								
Fixed income		15		15								
Life insurance contracts		23	19	42								
<b>Rabbi trust investments subtotal</b>	11	38	19	68								
<b>Total assets</b>	13	38	19	70					30			30
<b>Liabilities</b>												
Deferred compensation obligation		(6)		(6)		(1)		(1)				
Mark-to-market derivative liabilities <sup>(b)</sup>					(2)			(2)				
Effect of netting and allocation of collateral					2			2				
<b>Mark-to-market derivative liabilities subtotal</b>												
<b>Total liabilities</b>		(6)		(6)		(1)		(1)				

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<b>Total net assets (liabilities)</b>	\$ 13	\$ 32	\$ 19	\$ 64	\$	\$ (1)	\$	\$ (1)	\$ 30	\$	\$	\$ 30
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- (a) PHI excludes cash of \$13 million and \$16 million at June 30, 2016 and December 31, 2015 and includes long term restricted cash of \$19 million and \$18 million at June 30, 2016 and December 31, 2015 which is reported in other deferred debits on the balance sheet. Pepco excludes cash of \$5 million and \$5 million at June 30, 2016 and December 31, 2015. DPL excludes cash of \$4 million and \$5 million at June 30, 2016 and December 31, 2015. ACE excludes cash of \$4 million and \$3 million at June 30, 2016 and December 31, 2015 and includes long term restricted cash of \$19 million and \$18 million at June 30, 2016 and December 31, 2015 which is reported in other deferred debits on the balance sheet.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

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

(c) Prior to the PHI Merger, PHI recorded derivative assets for the embedded call and redemption features on the shares of Preferred Stock outstanding as of December 31, 2015. See Note 16 Mezzanine Equity for additional information. As a result of the PHI Merger, the PHI preferred stock derivative was reduced to zero as of March 23, 2016.

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, 2016 and 2015:

Three Months Ended	Investment Fund	Pledged Assets for Zion Station Decommissioning	Generation Mark-to- Market Derivatives	Other Investment	Total Generation	Successor			Total
						ComEd	PHI	Exelon	
	NDT	Station	Market			Mark-to- Market Derivatives	Life Insurance	Eliminated in Consolidation	
<b>June 30, 2016</b>									
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) <sup>(b)</sup>		(424)		1		(423)
Included in noncurrent payables to affiliates	8				8			(8)	
Included in payable for Zion Station decommissioning									
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									
<b>Balance at June 30, 2016</b>	<b>\$ 715</b>	<b>\$ 25</b>	<b>\$ 609</b>	<b>\$ 37</b>	<b>\$ 1,386</b>	<b>\$ (221)</b>	<b>\$ 20</b>	<b>\$</b>	<b>\$ 1,185</b>
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)

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

Six Months Ended	Pledged Assets				Total	ComEd	Successor PHI <sup>(c)</sup>	Eliminated in Consolidation	Exelon
	NDT Fund	Station Decommissioning	Mark-to- Market Derivatives	Other Investment					
<b>June 30, 2016</b>									
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) <sup>(b)</sup>		(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/liabilities						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 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 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, respectively.

(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 and DPL for the three and six months ended June 30, 2016.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

Three Months Ended	NDT Fund Investments	Pledged Assets for Zion Station decommissioning	Generation	Other Investments	Total Generation	ComEd	Eliminated in Consolidation	Exelon
			Mark-to- Market Derivatives			Mark-to- Market Derivatives		Total
<b>June 30, 2015</b>								
Balance as of March 31, 2015	\$ 612	\$ 44	\$ 1,066	\$ 3	\$ 1,725	\$ (241)		\$ 1,484
Total realized / unrealized gains (losses)								
Included in net income	2		(7) <sup>(b)</sup>		(5)			(5)
Included in noncurrent payables to affiliates	7				7		(7)	
Included in payable for Zion Station decommissioning		(2)			(2)			(2)
Included in regulatory assets						18	7	25
Change in collateral			(30)		(30)			(30)
Purchases, sales, issuances and settlements								
Purchases	79	1	16	27	123			123
Sales		(2)	(5)		(7)			(7)
Settlements	(33)				(33)			(33)
Transfers into Level 3			11		11			11
Transfers out of Level 3			(30)		(30)			(30)
Balance as of June 30, 2015	\$ 667	\$ 41	\$ 1,021	\$ 30	\$ 1,759	\$ (223)		\$ 1,536
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, 2015	\$ 2	\$	\$ 175	\$	\$ 177	\$	\$	\$ 177

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

Six Months Ended	NDT Fund Investments	Pledged Assets for Zion Station decommissioning	Generation		Total Generation	ComEd	Exelon
			Mark-to- Market Derivatives	Other Investments		Mark-to- Market Derivatives <sup>(a)</sup>	Eliminated in Consolidation
<b>June 30, 2015</b>							
Balance as of December 31, 2014	\$ 605	\$ 50	\$ 1,050	\$ 3	\$ 1,708	\$ (207)	\$ 1,501
Total realized / unrealized gains (losses)							
Included in net income	4		(39) <sup>(b)</sup>		(35)		(35)
Included in noncurrent payables to affiliates	17				17		(17)
Included in payable for Zion Station decommissioning		1			1		1
Included in regulatory assets						(16)	17
Change in collateral			(18)		(18)		(18)
Purchases, sales, issuances and settlements							
Purchases	107	1	57	27	192		192
Sales	(8)	(11)	(5)		(24)		(24)
Settlements	(62)				(62)		(62)
Transfers into Level 3	4		11		15		15
Transfers out of Level 3			(35)		(35)		(35)
Balance as of June 30, 2015	\$ 667	\$ 41	\$ 1,021	\$ 30	\$ 1,759	\$ (223)	\$ 1,536
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, 2015	\$ 3	\$	\$ 355	\$	\$ 358	\$	\$ 358

(a) Includes \$14 million of increases in fair value and 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, 2015. Includes \$22 million of decreases in fair value and realized losses due to settlements of \$6 million for the six months ended June 30, 2015.

(b) Includes an increase for the reclassification of \$182 million and \$394 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and six months ended June 30, 2015, respectively.

PHI	Successor Three Months Ended June 30, 2016		Predecessor Three Months Ended June 30, 2015	
	Life Insurance Contracts		Preferred Stock	Life Insurance Contracts
Beginning Balance	\$	20	\$ 3	\$ 19
Total realized / unrealized gains (losses)				
Included in net income		1		2
Purchases, sales, issuances and settlements				
Issuances		(1)		(1)
Settlements				
Ending Balance	\$	20	\$ 3	\$ 20

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The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities for the period	\$	1	\$	\$	1
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**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

	<i>Successor</i> March 24, 2016 to June 30, 2016	<i>Predecessor</i> January 1, 2016 to March 23, 2016	<i>Predecessor</i> Six Months Ended June 30, 2015
	Life Insurance Contracts	Life Preferred Insurance Stock Contracts	Life Preferred Insurance Stock Contracts
<b>PHI</b>			
Beginning Balance	\$ 20	\$ 18	\$ 19
Total realized / unrealized gains (losses)			
Included in net income	1	(18)	1
Purchases, sales, issuances and settlements			
Issuances	(1)		(1)
Settlements			(1)
Ending Balance	\$ 20	\$ 20	\$ 20

The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities for the period	\$ 1	\$ 1	\$ 2
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	Three Months Ended June 30, 2016 Pepco Life Insurance Contracts	Three Months Ended June 30, 2015 Pepco Life Insurance Contracts
Balance as of March 31	\$ 20	\$ 19
Total realized / unrealized gains (losses)		
Included in net income	1	2
Purchases, sales, issuances and settlements		
Issuances	(1)	(1)
Settlements		
Balance as of June 30	\$ 20	\$ 20

The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities for the period	\$ 1	\$ 1
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	Six Months Ended June 30, 2016 Pepco Life Insurance Contracts	Six Months Ended June 30, 2015 Pepco Life Insurance Contracts	DPL Life Insurance Contracts
Balance as of December 31	\$ 19	\$ 18	\$ 1
Total realized / unrealized gains (losses)			
Included in net income	2	3	
Purchases, sales, issuances and settlements			
Issuances	(1)	(1)	

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Settlements

(1)

Balance as of June 30	\$	20	\$	20	\$
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities for the period	\$	2	\$	2	\$

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

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, 2016 and 2015:

	Operating Revenues	Generation Purchased Power and Fuel	Other, net <sup>(a)</sup>	Operating Revenues	Exelon Purchased Power and Fuel	Other, net <sup>(a)</sup>
Total gains (losses) included in net income for the three months ended June 30, 2016	\$ (462)	\$ 34	\$ 4	\$ (462)	\$ 34	\$ 5
Total gains (losses) included in net income for the six months ended June 30, 2016	(413)	(21)	6	(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	(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	(20)	(25)	5

	Operating Revenues	Generation Purchased Power and Fuel	Other, net <sup>(a)</sup>	Operating Revenues	Exelon Purchased Power and Fuel	Other, net <sup>(a)</sup>
Total gains (losses) included in net income for the three months ended June 30, 2015	\$ (17)	\$ 10	\$ 2	\$ (17)	\$ 10	\$ 2
Total gains (losses) included in net income for the six months ended June 30, 2015	(27)	(12)	4	(27)	(12)	4
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2015	171	4	2	171	4	2
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2015	340	15	3	340	15	3

	Successor PHI	Predecessor PHI	Pepco
	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Three Months Ended June 30, 2015
	Other, net	Other, net	Other, net
Total gains (losses) included in net income	\$ 1	\$ 2	\$ 1
Change in the unrealized gains (losses) relating to assets and liabilities held	1	1	1

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

	<i>Successor PHI</i>	<i>Predecessor PHI</i>	<i>Pepco</i>
	March 24, 2016 to June 30, 2016	January 1, 2016 to March 23, 2016	Six Months Ended June 30, 2016
	Other, net	Other, net	Other, net
Total gains (losses) included in net income	\$ 1	\$ (17)	\$ 3
Change in the unrealized gains (losses) relating to assets and liabilities held	1	1	2

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

**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, as further described in Note 16 Mezzanine Equity, 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 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, Fixed Income and Other. 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

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

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, balanced 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 interest rate swaps to manage risk are recorded at fair value. Derivative instruments 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

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

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 not highly observable.

As of June 30, 2016, Generation has outstanding commitments to invest in middle market lending, private equity investments and real estate investments of approximately \$320 million, \$37 million, and \$479 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, 2016. 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, 2016, 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 predominately at liquid trading points.

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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, PECO, PHI, Pepco and DPL)***

*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.

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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 \$2.67 and \$0.32 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. See ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for information regarding the maturity by year of the Registrants' mark-to-market derivative assets and liabilities.

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.



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The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade		Fair Value at June 30, 2016	Valuation Technique	Unobservable Input	Range	
Mark-to-market derivatives Economic Hedges (Exelon and Generation) <sup>(a)(c)</sup>		\$ 493	Discounted Cash Flow	Forward power price	\$8 \$130	
					Forward gas price	\$1.74 \$10.19
				Option Model	Volatility percentage	5% 353%
Mark-to-market derivatives Proprietary trading (Exelon and Generation) <sup>(a)(c)</sup>		\$ (3)	Discounted Cash Flow	Forward power price	\$12 \$84	
Mark-to-market derivatives (Exelon and ComEd)		\$ (221)	Discounted Cash Flow	Forward heat rate <sup>(b)</sup>	8x 9x	
					Marketability reserve	3% 8%
					Renewable factor	88% 120%

(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 \$119 million as of June 30, 2016.

Type of trade		Fair Value at December 31, 2015	Valuation Technique	Unobservable Input	Range	
Mark-to-market derivatives Economic Hedges (Exelon and Generation) <sup>(a)(c)</sup>		\$ 857	Discounted Cash Flow	Forward power price	\$11 \$88	
					Forward gas price	\$1.18 \$8.95
				Option Model	Volatility percentage	5% 152%
Mark-to-market derivatives Proprietary trading (Exelon and Generation) <sup>(a)(c)</sup>		\$ (7)	Discounted Cash Flow	Forward power price	\$13 \$78	
Mark-to-market derivatives (Exelon and ComEd)		\$ (247)	Discounted Cash Flow	Forward heat rate <sup>(b)</sup>	9x 10x	
					Marketability reserve	3.5% 7%
					Renewable factor	87% 128%

- (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 \$201 million as of December 31, 2015.

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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 valuations of comparable companies, discounting the forecasted cash flows of the portfolio company, estimating the liquidation or collateral value of the portfolio company or its assets, considering offers from third parties to buy the portfolio company, its historical and projected financial results, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied to the prices of comparable companies 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. For a sample of its Level 3 investments, Generation reviewed independent valuations and reviewed the assumptions in the detailed pricing models used by the fund managers.

*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

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

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, 2016, the proportion of expected generation hedged for the major reportable segments is 97%-100%, 78%-81% and 47%-50% for 2016, 2017 and 2018, 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 for capacity 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.

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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 2015 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 2015 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 2015 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 30% 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

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

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

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

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 1,289 GWhs and 2,509 GWhs for the three and six months ended June 30, 2016, respectively, and 1,657 GWhs and 3,465 GWhs for the three and six months ended June 30, 2015, 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, 2016, Exelon had \$800 million of notional amounts of fixed-to-floating hedges outstanding, and Exelon and Generation had \$764 million and \$674 million of notional amounts of floating-to-fixed hedges outstanding, respectively. Assuming the fair value and cash flow 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, 2016. 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, 2016.

Description	Generation					Exelon Corporate		Exelon Total
	Derivatives Designated as		Proprietary Trading <sup>(a)</sup>	Collateral and Netting <sup>(b)</sup>		Derivatives Designated as		
	Hedging Instruments	Economic Hedges		Subtotal	Hedging Instruments	Total		
Mark-to-market derivative assets (current assets)	\$	\$ 14	\$ 6	\$ (11)	\$ 9	\$	\$ 9	
Mark-to-market derivative assets (noncurrent assets)		14	5	(12)	7	47	54	
<b>Total mark-to-market derivative assets</b>		<b>28</b>	<b>11</b>	<b>(23)</b>	<b>16</b>	<b>47</b>	<b>63</b>	
Mark-to-market derivative liabilities (current liabilities)	(8)	(9)	(4)	12	(9)		(9)	
Mark-to-market derivative liabilities (noncurrent liabilities)	(13)	(10)	(5)	14	(14)	(2)	(16)	
<b>Total mark-to-market derivative liabilities</b>	<b>(21)</b>	<b>(19)</b>	<b>(9)</b>	<b>26</b>	<b>(23)</b>	<b>(2)</b>	<b>(25)</b>	
<b>Total mark-to-market derivative net assets (liabilities)</b>	<b>\$ (21)</b>	<b>\$ 9</b>	<b>\$ 2</b>	<b>\$ 3</b>	<b>\$ (7)</b>	<b>\$ 45</b>	<b>\$ 38</b>	





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- (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 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.

The following table provides a summary of the interest rate and foreign exchange hedge balances recorded by the Registrants as of December 31, 2015:

Description	Derivatives Designated as				Subtotal	Exelon Corporate Derivatives Designated as	
	Economic Hedges		Collateral and Netting <sup>(b)</sup>			Hedging Instruments	Total
	Hedging Instruments	Economic Hedges	Proprietary Trading <sup>(a)</sup>	and Netting <sup>(b)</sup>			
Mark-to-market derivative assets (current assets)	\$	\$ 10	\$ 10	\$ (5)	\$ 15	\$	\$ 15
Mark-to-market derivative assets (noncurrent assets)		10	5	(1)	14	25	39
<b>Total mark-to-market derivative assets</b>		<b>20</b>	<b>15</b>	<b>(6)</b>	<b>29</b>	<b>25</b>	<b>54</b>
Mark-to-market derivative liabilities (current liabilities)	(8)	(2)	(9)	11	(8)		(8)
Mark-to-market derivative liabilities (noncurrent liabilities)	(8)	(1)	(3)	4	(8)		(8)
<b>Total mark-to-market derivative liabilities</b>	<b>(16)</b>	<b>(3)</b>	<b>(12)</b>	<b>15</b>	<b>(16)</b>		<b>(16)</b>
<b>Total mark-to-market derivative net assets (liabilities)</b>	<b>\$ (16)</b>	<b>\$ 17</b>	<b>\$ 3</b>	<b>\$ 9</b>	<b>\$ 13</b>	<b>\$ 25</b>	<b>\$ 38</b>

- (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 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.

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

*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:

	Income Statement Location	Three Months Ended June 30,			
		2016	2015	2016	2015
		Gain (loss) on Swaps		Gain (loss) on Borrowings	
Exelon	Interest expense	\$ 5	\$ (11)	\$ (1)	\$ 16

	Income Statement Location	Six Months Ended June 30,			
		2016	2015	2016	2015
		Gain (loss) on Swaps		Gain (loss) on Borrowings	
Generation	Interest expense <sup>(a)</sup>	\$	\$ (1)	\$	\$
Exelon	Interest expense	22	(1)	(16)	9

(a) For the six months ended June 30, 2015, the loss on Generation swaps included \$1 million realized in earnings with an immaterial amount excluded from hedge effectiveness testing.

At June 30, 2016, Exelon had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of \$800 million, with a derivative asset of \$47 million. At December 31, 2015, Exelon had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of \$800 million, with a derivative asset of \$25 million. During the three and six months ended June 30, 2016, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a \$4 million and a \$6 million gain, respectively.

*Cash Flow Hedges.* During the second quarter of 2016, Exelon entered into \$90 million of floating-to-fixed forward starting interest rate swaps to manage a portion of the interest rate exposure associated with the anticipated issuance of debt. The swaps are designated as cash flow hedges. At June 30, 2016, Exelon had a \$1 million derivative liability related to the swaps.

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 the anticipated issuance of debt. 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 for additional information.

During the first quarter of 2016, Exelon entered into \$100 million of floating-to-fixed forward starting interest rate swap 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 third quarter of 2014, ExGen Texas Power, LLC, 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 2015 Form 10-K for additional information regarding the financing. The swaps have a notional amount of \$497 million as of June 30, 2016 and



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

expire in 2019. The swap was designated as a cash flow hedge in the fourth quarter of 2014. At June 30, 2016, the subsidiary had a \$18 million derivative liability related to the swap.

During the first quarter of 2014, ExGen Renewables I, LLC, 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 2015 Form 10-K for additional information regarding the financing. The swaps have a notional amount of \$177 million as of June 30, 2016 and expire in 2020. The swaps are designated as cash flow hedges. At June 30, 2016, the subsidiary had a \$4 million derivative liability related to the swaps.

During the second quarter of 2002, PHI entered into treasury rate lock transactions in anticipation of the issuance of several series of fixed-rate debt commencing in August 2002 to manage a portion of its interest rate exposure. Upon issuance of the fixed-rate debt in August 2002, the treasury rate locks were terminated at a loss and the loss was deferred in AOCI. As a result of the PHI Merger, the remaining unamortized deferred loss recorded in AOCI was adjusted to zero through application of purchase accounting.

During the three and six months ended June 30, 2016 and 2015, 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 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 2015 Form 10-K for additional information regarding the financing. During the first quarter of 2016, upon the issuance of debt, Generation terminated the swaps. The total notional amount of the swaps were \$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 2015 Form 10-K for additional information regarding the financing. During the first quarter of 2016, upon the issuance 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.

During the second quarter 2015, upon the issuance of debt, Exelon terminated \$2,400 million of floating-to-fixed forward starting interest rate swaps. As a result of the termination of the swaps, Exelon realized a \$64 million loss during the second quarter of 2015.

At June 30, 2016, Generation had immaterial notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and \$100 million in notional amounts of foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international commodity transactions 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

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

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 initial margin on exchange positions, is aggregated in the collateral and netting column. As of June 30, 2016 and December 31, 2015, \$10 million and \$3 million of cash collateral posted, 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.

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(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 June 30, 2016:

Derivatives	Generation				ComEd	DPL			Successor	Total
	Economic Hedges	Proprietary Trading	and Netting <sup>(a)</sup>	Subtotal <sup>(b)</sup>	Economic Hedges <sup>(c)</sup>	Economic and Netting <sup>(a)</sup>	Subtotal	PHI	Exelon	
Mark-to-market derivative assets (current assets)	\$ 4,089	\$ 99	\$ (3,438)	\$ 750	\$	\$ 1	\$ (1)	\$	\$	\$ 750
Mark-to-market derivative assets (noncurrent assets)	1,846	28	(1,382)	492						492
<b>Total mark-to-market derivative assets</b>	<b>5,935</b>	<b>127</b>	<b>(4,820)</b>	<b>1,242</b>		<b>1</b>	<b>(1)</b>			<b>1,242</b>
Mark-to-market derivative liabilities (current liabilities)	(3,797)	(94)	3,766	(125)	(18)					(143)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,761)	(37)	1,575	(223)	(203)					(426)
<b>Total mark-to-market derivative liabilities</b>	<b>(5,558)</b>	<b>(131)</b>	<b>5,341</b>	<b>(348)</b>	<b>(221)</b>					<b>(569)</b>
<b>Total mark-to-market derivative net assets (liabilities)</b>	<b>\$ 377</b>	<b>\$ (4)</b>	<b>\$ 521</b>	<b>\$ 894</b>	<b>\$ (221)</b>	<b>\$ 1</b>	<b>\$ (1)</b>	<b>\$</b>	<b>\$</b>	<b>\$ 673</b>

- (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 \$159 million and \$88 million, respectively, and current and noncurrent liabilities are shown net of collateral of \$170 million and \$104 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was \$521 million at June 30, 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.

**Table of Contents****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, 2015:

Description	Generation				ComEd	Exelon	DPL			Predecessor			
	Economic Hedges	Proprietary Trading	and Netting <sup>(a)</sup>	Subtotal <sup>(b)</sup>			Economic Hedges <sup>(c)</sup>	Total Derivatives	Economic Hedges <sup>(e)</sup>	and Netting <sup>(a)</sup>	Subtotal	PHI Corporate	PHI
												Other <sup>(d)</sup>	Total Derivatives
Mark-to-market derivative assets (current assets)	\$ 5,236	\$ 108	\$ (3,994)	\$ 1,350	\$	\$ 1,350	\$	\$	\$	\$ 18	\$ 18		
Mark-to-market derivative assets (noncurrent assets)	1,860	22	(1,163)	719		719							
Total mark-to-market derivative assets	7,096	130	(5,157)	2,069		2,069				18	18		
Mark-to-market derivative liabilities (current liabilities)	(4,907)	(94)	4,827	(174)	(23)	(197)	(2)	2					
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,673)	(33)	1,564	(142)	(224)	(366)							
Total mark-to-market derivative liabilities	(6,580)	(127)	6,391	(316)	(247)	(563)	(2)	2					
Total mark-to-market derivative net assets (liabilities)	\$ 516	\$ 3	\$ 1,234	\$ 1,753	\$ (247)	\$ 1,506	\$ (2)	\$ 2	\$	\$ 18	\$ 18		

- (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 \$352 million and \$180 million, respectively, and current and noncurrent liabilities are shown net of collateral of \$480 million and \$222 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was \$1,234 million at December 31, 2015.
- (c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.
- (d) Prior to the PHI Merger, PHI recorded derivative assets for the embedded call and redemption features on the shares of Preferred Stock outstanding as of December 31, 2015. See Note 16 Mezzanine Equity for additional information. As a result of the PHI Merger, the PHI preferred stock derivative was reduced to zero as of March 23, 2016.
- (e) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.



**Table of Contents****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 AOCI related to cash flow hedges for the six months ended June 30, 2016 and 2015, containing information about the changes in the fair value of cash flow hedges and the reclassification from AOCI into results of operations. The amounts reclassified from AOCI, when combined with the impacts of the hedged transactions, result in the ultimate recognition of net revenues or expenses at the contractual price.

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

	Income Statement Location	Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Six Months Ended June 30, 2016		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		(1)	(4)
Reclassifications from AOCI to net income	Interest Expense	(3) <sup>(a)</sup>	(3) <sup>(a)</sup>
Accumulated OCI derivative loss at June 30, 2016		\$ (25)	\$ (26)

	Income Statement Location	Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended June 30, 2015		Total Cash Flow Hedges	Total Cash Flow Hedges
AOCI derivative loss at March 31, 2015		\$ (23)	\$ (22)
Effective portion of changes in fair value			1
Reclassifications from AOCI to net income	Interest Expense	2	2
AOCI derivative loss at June 30, 2015		\$ (21)	\$ (19)

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Six Months Ended June 30, 2015	Income Statement Location	Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation Total Cash Flow Hedges	Exelon Total Cash Flow Hedges
Accumulated OCI derivative loss at December 31, 2014		\$ (18)	\$ (28)
Effective portion of changes in fair value		(6)	(10)
Reclassifications from AOCI to net income	Other, net		16 <sup>(b)</sup>
Reclassifications from AOCI to net income	Interest Expense	5	5
Reclassifications from AOCI to net income	Operating Revenues	(2)	(2)
Accumulated OCI derivative loss at June 30, 2015		\$ (21)	\$ (19)

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

(b) Amount is net of related income tax benefit of \$10 million for the six months ended June 30, 2015.

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

The effect of Exelon's and Generation's former energy-related cash flow hedge activity on pre-tax earnings based on the reclassification adjustment from AOCI to earnings was a \$2 million pre-tax gain for the three and six months ended June 30, 2015. Neither Exelon nor Generation will incur changes in cash flow hedge ineffectiveness in future periods relating to energy-related hedges positions as all were de-designated prior to the Constellation merger date.

*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, 2016 and 2015, 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 at settlement represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Operating Revenues	Generation Purchased Power and Fuel	Total	Exelon Total
<b>Three Months Ended June 30, 2016</b>				
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)

	Operating Revenues	Generation Purchased Power and Fuel	Total	Exelon Total
<b>Six Months Ended June 30, 2016</b>				
Change in fair value of commodity positions	\$ (153)	\$ 109	\$ (44)	\$ (44)
Reclassification to realized at settlement 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 at settlement of treasury positions	(4)		(4)	(4)

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Net treasury mark-to-market gains (losses)	(8)		(8)	(8)
Net mark-to-market gains (losses)	\$ (553)	\$ 352	\$ (201)	\$ (201)

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

	Operating Revenues	Generation Purchased Power and Fuel	Total	Exelon Corporate Interest Expense	Exelon Total
<b>Three Months Ended June 30, 2015</b>					
Change in fair value of commodity positions	\$ 197	\$ 110	\$ 307	\$	\$ 307
Reclassification to realized at settlement of commodity positions	(167)	100	(67)		(67)
Net commodity mark-to-market gains (losses)	30	210	240		240
Change in fair value of treasury positions	(3)		(3)	114	111
Reclassification to realized at settlement of treasury positions	(2)		(2)	64	62
Net treasury mark-to-market gains (losses)	(5)		(5)	178	173
Net mark-to-market gains (losses)	\$ 25	\$ 210	\$ 235	\$ 178	\$ 413

	Operating Revenues	Generation Purchased Power and Fuel	Total	Exelon Corporate Interest Expense	Exelon Total
<b>Six Months Ended June 30, 2015</b>					
Change in fair value of commodity positions	\$ 377	\$ 15	\$ 392	\$	\$ 392
Reclassification to realized at settlement of commodity positions	(204)	203	(1)		(1)
Net commodity mark-to-market gains (losses)	173	218	391		391
Change in fair value of treasury positions	10		10	36	46
Reclassification to realized at settlement of treasury positions	(4)		(4)	64	60
Net treasury mark-to-market gains (losses)	6		6	100	106
Net mark-to-market gains (losses)	\$ 179	\$ 218	\$ 397	\$ 100	\$ 497

*Proprietary Trading Activities (Exelon and Generation).* For the three and six months ended June 30, 2016 and 2015, 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 revenue 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 at settlement represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.



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

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
Change in fair value of commodity positions	\$ 5	\$ 7	\$ 14	\$ 8
Reclassification to realized at settlement of commodity positions	(5)	(7)	(11)	(5)
Net commodity mark-to-market gains (losses)			3	3
Change in fair value of treasury positions			(2)	4
Reclassification to realized at settlement of treasury positions	(1)	(2)	1	(6)
Net treasury mark-to-market gains (losses)	(1)	(2)	(1)	(2)
Total net mark-to-market gains (losses)	\$ (1)	\$ (2)	\$ 2	\$ 1

**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.

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

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of June 30, 2016. 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 and Nodal commodity exchanges, further discussed in ITEM 3. **QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.** Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of \$26 million, \$40 million, \$36 million, \$50 million, \$15 million, and \$8 million as of June 30, 2016, respectively.

Rating as of June 30, 2016	Total Exposure			Number of Counterparties Greater than 10%		Net Exposure of Counterparties Greater than 10%	
	Before Collateral	Credit Collateral <sup>(a)</sup>	Net Exposure	of Net Exposure	of Net Exposure		
Investment grade	\$ 965	\$ 12	\$ 953	1	\$	356	
Non-investment grade	55	24	31				
No external ratings							
Internally rated investment grade	373	1	372				
Internally rated non-investment grade	46	7	39				
Total	\$ 1,439	\$ 44	\$ 1,395	1	\$	356	

Net Credit Exposure by Type of Counterparty	As of June 30, 2016
Financial institutions	\$ 96
Investor-owned utilities, marketers, power producers	573
Energy cooperatives and municipalities	696
Other	30
Total	\$ 1,395

(a) As of June 30, 2016, credit collateral held from counterparties where Generation had credit exposure included \$9 million of cash and \$35 million of letters of credit.

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, 2016, 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 2015 Form 10-K for additional information.



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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

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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, 2016, PECO had no 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, 2016, PECO had no 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 2015 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, 2016, 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, 2016, 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, 2016, Pepco's, DPL's and ACE's net credit exposures to suppliers were immaterial.

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

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 6 Regulatory Matters of the PHI 2015 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, 2016, 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.

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:

	June 30, 2016	December 31, 2015
<b>Credit-Risk Related Contingent Feature</b>		
Gross Fair Value of Derivative Contracts Containing this Feature <sup>(a)</sup>	\$ (912)	\$ (932)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements <sup>(b)</sup>	657	684
<b>Net Fair Value of Derivative Contracts Containing This Feature<sup>(c)</sup></b>	<b>\$ (255)</b>	<b>\$ (248)</b>

(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.

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

- (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 \$548 million and letters of credit posted of \$441 million and cash collateral held of \$14 million and letters of credit held of \$46 million as of June 30, 2016 for external counterparties with derivative positions. Generation had cash collateral posted of \$1,267 million and letters of credit posted of \$497 million and cash collateral held of \$21 million and letters of credit held of \$78 million at December 31, 2015 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 \$2.0 billion as of June 30, 2016 and December 31, 2015, 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, 2016, Generation's swaps were in a liability position with a fair value of \$7 million and Exelon's swaps were in an asset position, with a fair value of \$39 million.

See Note 25 Segment Information of the Exelon 2015 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, 2016, ComEd held \$1 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, 2016, 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, 2016, it would have been required to post approximately \$3 million of collateral to its counterparties. See Note 3 Regulatory Matters of the Exelon 2015 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, 2016, PECO was not required to post collateral for any of these

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

agreements. If PECO lost its investment grade credit rating as of June 30, 2016, PECO could have been required to post approximately \$26 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, 2016, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of June 30, 2016, BGE could have been required to post approximately \$31 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, 2016, DPL could have been required to post an additional amount of approximately \$9 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, 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. Pepco, DPL and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and short-term notes.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(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, 2016 and December 31, 2015:

<b>Commercial Paper Borrowings</b>	<b>June 30, 2016</b>	<b>December 31, 2015</b>
ComEd	\$ 35	\$ 294
BGE	208	210
PHI Corporate		484
Pepco		64
DPL		105
ACE		5

**Short-Term Loan Agreements**

On July 30, 2015, PHI entered into a \$300 million term loan agreement. 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, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.95%, and all indebtedness thereunder is unsecured, and the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement, must be repaid in full on or before July 28, 2016. On April 4, 2016, PHI repaid \$300 million of its term loan in full.

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, and the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement, must be repaid in full on or before March 27, 2017. The loan agreement is reflected in Exelon's and PHI's Consolidated Balance Sheets within Short-term borrowings.

On February 22, 2016, Generation and EDF entered into separate member revolving promissory notes with CENG to finance short-term working capital needs. The notes are scheduled to mature on January 31, 2017 and bear interest at a variable rate equal to LIBOR plus 1.75%. As of June 30, 2016, \$10 million was outstanding under each note. The \$10 million note outstanding between Generation and CENG is eliminated in consolidation and therefore not reflected in Exelon's or Generation's Consolidated Balance Sheets. The \$10 million note with EDF is reflected in Exelon's and Generation's Consolidated Balance Sheet within Short-term borrowings. On July 25, 2016, CENG paid off the outstanding \$10 million balance under each note.

**Credit Agreements**

On January 5, 2016, Generation entered into a credit agreement establishing a \$150 million bilateral credit facility, scheduled to mature in January of 2019. This facility will solely be utilized by Generation to issue lines of credit. This facility does not back Generation's commercial paper program.

On April 1, 2016, the credit agreement for CENG's \$100 million bilateral credit facility was amended to increase the overall facility size to \$200 million. This facility is utilized by CENG to fund working capital and capital projects. The facility does not back Generation's commercial paper program.

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



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

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) aligned its financial covenant from debt to capitalization leverage ratio to interest coverage ratio.

**Variable Rate Demand Bonds**

As of June 30, 2016 and December 31, 2015, \$105 million in variable rate demand bonds issued by DPL were outstanding and are included in the Long-term debt due within one year on Exelon's, PHI's and DPL's Consolidated Balance Sheets. See Note 10 Debt of the PHI 2015 Form 10-K for additional information.

**Long-Term Debt****Issuance of Long-Term Debt**

During the six months ended June 30, 2016, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon Corporate	Senior Unsecured Notes	2.45%	April 15, 2021	\$ 300	Repay commercial paper issued by PHI and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes	3.40%	April 15, 2026	\$ 750	Repay commercial paper issued by PHI and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes	4.45%	April 15, 2046	\$ 750	Repay commercial paper issued by PHI and for general corporate purposes
Generation	Renewable Power Generation Nonrecourse Debt	4.11%	March 31, 2035	\$ 150	Paydown long term debt obligations at Sacramento PV Energy and Constellation Solar Horizons and for general corporate purposes.
Generation	Albany Green Energy Project Financing	LIBOR + 1.25%	November 17, 2017	\$ 63	Albany Green Energy biomass generation development
Generation	Energy Efficiency Project Financing	3.17%	February 1, 2037	\$ 16	Funding to install energy conservation measures in Brooklyn, NY
Generation	Energy Efficiency Project Financing	3.90%	February 1, 2018	\$ 7	Funding to install energy conservation measures for the Naval Station Great Lakes project



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
ComEd	First Mortgage Bonds, Series 120	2.55%	June 15, 2026	\$ 500	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes.
ComEd	First Mortgage Bonds, Series 121	3.65%	June 15, 2046	\$ 700	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes.
Pepco	Energy Efficiency Project Financing	3.30%	August 15, 2017	\$ 1	Funding to install energy conservation measures for the DOE Germantown project

***CEU Upstream Nonrecourse Debt***

In July 2011, CEU Holdings, LLC, a wholly owned subsidiary of Generation, entered into a 5-year reserve based lending agreement (RBL) associated with certain Upstream oil and gas properties that it owns. The lenders do not have recourse against Exelon or Generation in the event of default pursuant to the RBL. Borrowings under this arrangement are secured by the assets and equity of CEU Holdings. The commitment level can be decreased if the assets no longer support the current borrowing base, which may result in repayment of a portion or all of the outstanding balance, or potential foreclosure of the assets. The commitment can be increased up to \$500 million if the assets support a higher borrowing base and CEU Holdings is able to obtain additional commitments from lenders. Calculations of the borrowing base are impacted by projected production and commodity prices. The facility was amended and extended on January 14, 2014 through January 2019. As of December 31, 2015, \$68 million was outstanding under the facility with interest payable monthly at a variable rate equal to LIBOR plus 2.50% and the borrowing base committed under the facility was \$85 million. The outstanding balance was classified as Long-term debt on Exelon's and Generation's Consolidated Balance Sheets.

In February 2016, as part of their semi-annual borrowing base re-determination testing, the RBL lenders notified CEU Holdings that the RBL borrowing base was decreased to \$45 million, resulting in a borrowing base deficiency under the RBL of \$23 million. Given the decline in value of the Upstream assets resulting from lower commodity prices, CEU Holdings chose not to provide the lenders with a formal plan for curing the borrowing base deficiency by March 31, 2016, as was required by the RBL. The lenders have sent CEU Holdings a notice of event of default and demand for cure. On March 31, 2016, \$7 million of the debt was repaid using CEU Holdings' cash, resulting in an outstanding debt balance of \$61 million with interest payable monthly at a variable rate equal to LIBOR plus 2.75% and a borrowing base deficiency under the RBL of \$16 million. At March 31, 2016, the outstanding debt balance of \$61 million was classified within Long-term debt due within one year on Exelon's and Generation's Consolidated Balance Sheets.

On June 16, 2016, CEU Holdings executed a forbearance agreement with the lenders which included terms stipulating roles and responsibilities governing a sales process, approval of the sale of the assets to be at the discretion of the lenders, and a sales timetable, with ultimate execution of the sales agreement expected to occur by December 31, 2016. Upon disposition of the assets and the satisfaction of certain other conditions, CEU

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

Holdings will be released of its obligations regardless of the amount of asset sale proceeds received. The ultimate resolution of this matter has no direct effect on any Exelon or Generation credit facilities or other debt of an Exelon entity. See Note 14 Debt and Credit Agreements of the Exelon 2015 Form 10-K, Note 5 Mergers, Acquisitions and Dispositions and Note 6 Impairment of Long-Lived Assets for additional information.

**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, 2016									
	Exelon	Generation <sup>(e)</sup>	ComEd	PECO	BGE <sup>(f)</sup>	PHI	Pepco	DPL	ACE	Successor
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	2.3	(116.7)	4.8	0.3	2.0	6.1	3.5	4.8	5.9	
Qualified nuclear decommissioning trust fund income	5.7	591.2								
Domestic production activities deduction										
Health care reform legislation										
Amortization of investment tax credit, net deferred taxes	(1.8)	(157.8)	(0.2)	(0.1)	(0.4)	(0.3)	(0.1)	(0.6)	(1.6)	
Plant basis differences <sup>(d)</sup>	(6.9)		(0.4)	(11.3)	(20.6)	(7.0)	(5.7)	(3.5)	(7.1)	
Production tax credits and other credits	(5.8)	(603.0)								
Noncontrolling interests	0.9	94.4								
Statute of limitations expiration	(1.7)	(410.8)								
Merger expenses	0.2					1.0	0.2	3.1		
Other <sup>(c)</sup>	(3.3)	(52.3)	(0.6)	(5.2)	(1.0)	1.0	(1.0)	1.2	7.8	
Effective income tax rate	24.6%	(620.0)%	38.6%	18.7%	15.0%	35.8%	31.9%	40.0%	40.0%	

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

	Three Months Ended June 30, 2015									
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE	Predecessor
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	3.9	3.4	5.6	1.4	5.3	5.3	5.0	5.0	9.9	
Qualified nuclear decommissioning trust fund income	(1.0)	(1.7)								
Domestic production activities deduction	(2.0)	(3.4)								
Health care reform legislation					0.1					
Amortization of investment tax credit, net deferred taxes	(0.6)	(0.9)	(0.3)	(0.1)	(0.2)	(0.3)		(1.0)	(0.2)	
Plant basis differences	(1.0)		(0.1)	(9.0)	(0.5)	(7.3)	(8.3)	(4.2)	(0.1)	
Production tax credits and other credits	(1.3)	(2.2)								
Noncontrolling interests	(0.4)	(0.6)								
Other	1.4	2.0	0.5	0.5	0.8	1.1	(1.7)	3.7	(4.6)	
Effective income tax rate	34.0%	31.6%	40.7%	27.8%	40.5%	33.8%	30.0%	38.5%	40.0%	

**Table of Contents****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 <sup>(a)</sup>	DPL <sup>(a)</sup>	ACE <sup>(a)</sup>	PHI <sup>(a)</sup>	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 <sup>(b)</sup>	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									
Domestic production activities deduction											
Health care reform legislation 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 <sup>(d)</sup>	(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 interests	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 <sup>(c)</sup>	(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%	

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

	Six Months Ended June 30, 2015									
	<i>Predecessor</i>									
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE	
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	3.2	3.0	5.3	1.3	5.3	6.4	4.1	5.5	5.5	
Qualified nuclear decommissioning trust fund income	0.6	0.9								
Domestic production activities deduction	(2.1)	(3.4)								
Health care reform legislation					0.2					
Amortization of investment tax credit, including deferred taxes on basis difference	(0.8)	(1.1)	(0.3)	(0.1)	(0.1)	(0.4)		(0.4)	(0.9)	
Plant basis differences	(1.1)		(0.2)	(7.5)	(0.3)	(6.1)	(8.2)	(1.5)	(1.7)	
Production tax credits and other credits	(1.6)	(2.5)								
Noncontrolling interests	(0.6)	(0.8)								
Other	0.8	0.6	0.4	0.2		(0.3)	(0.3)	0.8	(0.4)	
Effective income tax rate	33.4%	31.7%	40.2%	28.9%	40.1%	34.6%	30.6%	39.4%	37.5%	

- (a) 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.
- (b) Includes a remeasurement of uncertain state income tax positions for Pepco and DPL.
- (c) At PECO, includes a cumulative adjustment related to an anticipated gas repairs tax return accounting method change.
- (d) At BGE, includes a cumulative adjustment related to a regulatory asset.
- (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 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.
- (f) The effective tax rate for the quarter is disproportionately impacted due to the decline in pre-tax GAAP earnings and changes in other reconciling items.

**Accounting for Uncertainty in Income Taxes**

The Registrants have the following unrecognized tax benefits as of June 30, 2016 and December 31, 2015:

	<i>Successor</i>									
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE	
June 30, 2016	\$ 963	\$ 531	\$ (12)	\$	\$ 120	\$ 181	\$ 95	\$ 39	\$ 24	
	<i>Predecessor</i>									
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE	
December 31, 2015	\$ 1,101	\$ 534	\$ 142	\$	\$ 120	\$ 22	\$ 8	\$ 3	\$	

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Exelon and ComEd's unrecognized tax benefits changed by \$328 million and \$154 million, respectively, as of June 30, 2016 as a result of the lease termination on the like-kind exchange position discussed below. In

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

addition, as a result of the merger, an assessment and remeasurement of certain federal and state uncertain income tax positions resulted in an increase in unrecognized tax benefits at Exelon, PHI, Pepco, DPL and ACE of \$190 million, \$159 million, \$87 million, \$36 million and \$24 million, respectively.

**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, 2016, Exelon and ComEd have approximately \$75 million and \$(12) million of unrecognized state income tax benefits that could significantly decrease and increase, respectively, within the 12 months after the reporting date as a result of a decision or settlement in the like-kind exchange litigation described below. These unrecognized tax benefits, if recognized, would decrease Exelon's effective tax rate by \$75 million and increase ComEd's effective tax rate by \$12 million.

*Settlement of Income Tax Audits and Litigation*

As of June 30, 2016, Exelon, Generation, BGE, PHI, Pepco, and DPL have approximately \$300 million, \$67 million, \$120 million, \$113 million, \$71 million, and \$20 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, Generation, PHI, and Pepco have \$102 million, \$67 million, \$35 million, \$13 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 has been unable to reach agreement with the IRS regarding the dispute over the like-kind exchange position. The IRS has asserted that the Exelon purchase and leaseback transaction is 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 has asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities does not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS has also asserted a penalty of approximately \$90 million for a substantial understatement of tax.

Exelon disagrees with the IRS and continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO. Although Exelon has been and remains willing to settle the disagreement on terms commensurate with the hazards of litigation, Exelon does not believe a settlement is likely. Because Exelon believed, as of December 31, 2012, that it is more-likely-than-not that Exelon would prevail in litigation, Exelon and ComEd had no liability for unrecognized tax benefits with respect to the like-kind exchange position.

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit reversed the U.S. Court of Federal Claims and reached a decision for the government in Consolidated Edison v. United States. The Court disallowed Consolidated Edison's deductions stemming from its participation in a LILO transaction that the IRS also has characterized as a tax shelter.

In accordance with applicable accounting standards, Exelon is required to assess whether it is more-likely-than-not that it will prevail in litigation. Exelon continues to believe that its transaction is not a SILO and that it has a strong case on the merits. However, in light of the Consolidated Edison decision and Exelon's current determination that settlement is unlikely, Exelon has concluded that subsequent to December 31, 2012, it is no longer more-likely-than-not that its position will be sustained. As a result, in the first quarter of 2013 Exelon recorded a non-cash charge to earnings of approximately \$265 million, which represents the amount of interest expense (after-tax) and incremental state income tax expense for periods through March 31, 2013 that would be payable in the event that Exelon is unsuccessful in litigation. Of this amount, approximately \$172 million was recorded at ComEd. Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity. As such, ComEd recorded on its consolidated balance sheet as of March 31, 2013, a \$172 million receivable and non-cash equity contributions from Exelon. Exelon and ComEd will continue to accrue interest on the unpaid tax liabilities related to the uncertain tax position, and the charges arising from future interest accruals are not expected to be material to the annual operating earnings of Exelon or ComEd. In addition, ComEd will continue to record non-cash equity contributions from Exelon in the amount of the net after-tax interest charges attributable to ComEd in connection with the like-kind exchange position. Exelon continues to believe that it is unlikely that the IRS's assertion of penalties will ultimately be sustained and therefore no liability for the penalty has been recorded.

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 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. While the Tax Court could reach its decision as early as 2016, the litigation could take three to five years if an appeal is necessary. Decisions in the Tax Court are not controlled by the Federal Circuit's decision in Consolidated Edison.

In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, as of June 30, 2016, potential tax of \$460 million and after-tax interest of \$310 million, exclusive of penalties, could become payable (net of a \$65 million deposit made to the IRS in 2015). Of the above amounts, approximately \$275 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless. Interest will continue to accrue until such time as payment is made. An appeal of an adverse decision in the Tax Court would necessitate either the posting of a bond or the payment of the tax and interest for the tax years before the court.

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. On March 31, 2016, Exelon entered into an agreement to terminate its interests in the remaining two municipal-owned electric generation properties in exchange for \$360 million. As a result of the lease terminations, any remaining tax gain related to the LKE position taken in 1999 will no longer be deferred. In the event of a successful outcome in the litigation, Exelon will not be required to pay the after-tax interest described in the preceding paragraph (\$310 million as of June 30, 2016) but will be required to report the remaining \$460 million of tax due on the transaction in Exelon's 2014 and 2016 tax years. Of that approximately \$230 million is attributable to ComEd. The tax liabilities from the terminations will not result in a current year cash outflow due to the utilization of net operating losses and tax credit carryforwards.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****Long-Term State Tax Apportionment (Exelon, Generation and PHI)**

Exelon and Generation 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 and Generation to update their long-term state tax apportionment include significant changes in tax law and/or significant operational changes, such as the merger with PHI. As a result of the merger, Exelon and Generation reevaluated their long-term state tax apportionment for all states where they have state income tax obligations, which include Delaware, Illinois, Maryland, New Jersey, Pennsylvania, and Washington D.C., as well as other states. The total effect of revising the long-term state tax apportionment resulted in the recording of deferred state tax benefit in the amount of \$1 million and a state tax expense of \$6 million, net of tax, for Exelon and Generation, respectively. Further, Exelon and PHI recorded deferred state tax liabilities of \$59 million and \$8 million, net of tax, respectively, as part of purchase accounting during the first quarter of 2016.

**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 generally updates its ARO annually during the third quarter, 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, 2015 to June 30, 2016:

Nuclear decommissioning ARO at December 31, 2015 <sup>(a)</sup>	\$ 8,246
Accretion expense	215
Net increase due to changes in, and timing of, estimated cash flows	444
Costs incurred to decommission retired plants	(2)
Nuclear decommissioning ARO at June 30, 2016 <sup>(a)</sup>	\$ 8,903

(a) Includes \$11 million and \$7 million for the current portion of the ARO at June 30, 2016 and December 31, 2015, respectively, which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

During the six months ended June 30, 2016, Generation's nuclear ARO increased by approximately \$657 million, reflecting impacts of ARO updates completed during the first and second quarters of 2016 to reflect changes in amounts and timing of estimated decommissioning cash flows and impacts of year-to-date accretion of the ARO liability due to the passage of time.

In 2016, the ARO liability increased by \$444 million primarily driven by an increase of \$384 million associated with the June 2, 2016 announcement to early retire the Clinton and Quad Cities nuclear units on June 1, 2017 and June 1, 2018, respectively, as well as an increase of \$60 million primarily due to an increase in the estimated costs to decommission the Oyster Creek nuclear unit as a result of the completion of an updated decommissioning cost study. Refer to Note 7 – Early Nuclear Plant Retirements for additional information regarding the announced early retirements of Clinton and Quad Cities. The increase in the ARO liability for Clinton and Quad Cities incorporates the early shutdown dates (including fleet-wide impacts of spent nuclear



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

fuel removal and storage costs), increases the probabilities of longer term decommissioning scenarios, and reflects an increase in the estimated costs to decommission based on updated decommissioning cost studies reflecting the early retirement of these units.

The financial statement impact related to the increase in the ARO liability due to the changes in, and timing of, estimated cash flows resulted in a corresponding increase in Property, plant and equipment on Exelon's and Generation's Consolidated Balance Sheets. The majority of the increase in cost will be amortized over the remaining useful lives of the Clinton, Quad Cities and Oyster Creek nuclear plants, which are set to retire in 2017, 2018 and 2019, respectively.

***Nuclear Decommissioning Trust Fund Investments***

At June 30, 2016 and December 31, 2015, Exelon and Generation had NDT fund investments totaling \$10,737 million and \$10,342 million, respectively.

The following table provides unrealized gains on NDT funds for the three and six months ended June 30, 2016 and 2015:

	Exelon and Generation		Exelon and Generation	
	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net unrealized gains (losses) on decommissioning trust funds Regulatory Agreement Units <sup>(a)</sup>	\$ 52	\$ (133)	\$ 131	\$ (85)
Net unrealized gains (losses) on decommissioning trust funds Non-Regulatory Agreement Units <sup>(b)(c)</sup>	48	(96)	100	(56)

(a) Net unrealized gains 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 \$1 million of net unrealized gain related to the Zion Station pledged assets for the three months ended June 30, 2016. Excludes \$3 million and \$9 million of net unrealized gain related to the Zion Station pledged assets for the six months ended June 30, 2016 and 2015, respectively. Net unrealized gains related to Zion Station pledged assets are included in the Payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets.

(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.

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 26 Related Party Transactions of the Exelon 2015 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.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)*****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 2015 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 \$86 million which is included within the nuclear decommissioning ARO at June 30, 2016. 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, 2016 and December 31, 2015:

	<b>Exelon and Generation</b>	
	<b>June 30, 2016</b>	<b>December 31, 2015</b>
Carrying value of Zion Station pledged assets	\$ 161	\$ 206
Payable to Zion Solutions <sup>(a)</sup>	148	189
Current portion of payable to Zion Solutions <sup>(b)</sup>	94	99
Cumulative withdrawals by Zion Solutions to pay decommissioning costs <sup>(c)</sup>	834	786

(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 31, 2015. This report reflects the status of decommissioning funding assurance as of December 31, 2014. Due to increased cost



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

estimates received in the second half of 2014, Braidwood Units 1 and 2, and Byron Unit 2 did not meet the NRC's minimum funding assurance criteria as of December 31, 2014. NRC guidance provides licensees with two years or by the time of submitting the next biennial report (on or before March 31, 2017) to resolve funding assurance shortfalls. On February 4, 2016, Generation submitted to the NRC an updated decommissioning funding status report for Braidwood Units 1 and 2, and Byron Unit 2. This updated report reflected the recently approved license renewals for these units, and showed that the shortfall identified in the March 31, 2015 report has now been resolved and that Generation has provided adequate decommissioning funding assurance for each unit.

On March 31, 2016, Generation submitted its NRC required annual decommissioning funding status report as of December 31, 2015 for reactors that have been shut down or are within five years of shut down except for Zion Station which is included in a separate report to the NRC submitted by EnergySolutions (see Zion Station Decommissioning above). As of December 31, 2015, Generation provided adequate decommissioning funding assurance for all of its reactors that have been shut down or are within five years of shut down 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 in Note 16 Asset Retirement Obligations of Exelon's 2015 Form 10-K, the amount collected from PECO ratepayers will be adjusted in the next filing to the PAPUC with new rates effective January 1, 2018.

Generation will file its next decommissioning funding status report with the NRC by March 31, 2017. This report will reflect the status of decommissioning funding assurance as of December 31, 2016 and will reflect the impacts of the announced early retirements of Clinton and Quad Cities. A shortfall could require Exelon to post parental guarantees for Generation's share of the funding assurance. 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.

**13. Retirement Benefits (All Registrants)**

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

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. The legacy PHI pension and other postretirement benefit plans were initially remeasured on February 29, 2016 as a result of the short time between the merger close and the end of the first quarter of 2016, using current assumptions, including the discount rate. Exelon updated these amounts in June 2016 to reflect assumptions at March 31, 2016. The updated valuation resulted in a \$25 million reduction in the net obligation.

***Defined Benefit Pension and Other Postretirement Benefits***

During the first quarter of 2016, Exelon received an updated valuation of its legacy pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2016. This valuation resulted in an increase to the pension obligation of \$35 million and a decrease to the other postretirement benefit obligation of \$8 million. Additionally, accumulated other comprehensive loss increased by approximately \$2 million (after tax), regulatory assets increased by approximately \$27 million, and regulatory liabilities increased by approximately \$3 million.

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

The majority of the 2016 pension benefit cost for legacy Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 4.29%. The majority of the 2016 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.71% for funded plans and a discount rate of 4.29%.

The 2016 pension benefit costs for the legacy PHI plans are calculated using an expected long-term rate of return on plan assets of 6.50% and a discount rate of 3.96% for the majority of the pension plans. The 2016 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.75% and a discount rate of 3.80%.

A portion of the net periodic benefit cost for all plans is capitalized within the Consolidated Balance Sheets. The following table presents the components of Exelon's net periodic benefit costs, prior to capitalization, for the three and six months ended June 30, 2016 and 2015.

	<b>Pension Benefits</b>		<b>Other Postretirement Benefits</b>	
	<b>Three Months Ended</b>		<b>Three Months Ended</b>	
	<b>June 30,</b>		<b>June 30,</b>	
	<b>2016</b>	<b>2015</b>	<b>2016</b>	<b>2015</b>
Service cost	\$ 91	\$ 81	\$ 28	\$ 29
Interest cost	212	178	48	42
Expected return on assets	(292)	(256)	(42)	(37)
Amortization of:				
Prior service cost (benefit)	4	4	(47)	(44)
Actuarial loss	142	142	16	21
<b>Net periodic benefit cost</b>	<b>\$ 157</b>	<b>\$ 149</b>	<b>\$ 3</b>	<b>\$ 11</b>

	<b>Pension Benefits</b>		<b>Other Postretirement Benefits</b>	
	<b>Six Months Ended</b>		<b>Six Months Ended</b>	
	<b>June 30,</b>		<b>June 30,</b>	
	<b>2016<sup>(a)</sup></b>	<b>2015</b>	<b>2016<sup>(a)</sup></b>	<b>2015</b>
<b>Components of net periodic benefit cost:</b>				
Service cost	\$ 170	\$ 163	\$ 54	\$ 59
Interest cost	403	355	90	83
Expected return on assets	(555)	(513)	(80)	(75)
Amortization of:				
Prior service cost (benefit)	7	7	(91)	(88)
Actuarial loss	269	285	30	41
<b>Net periodic benefit cost</b>	<b>\$ 294</b>	<b>\$ 297</b>	<b>\$ 3</b>	<b>\$ 20</b>

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

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

	January 1, 2016 to March 23, 2016	Predecessor PHI		January 1, 2016 to March 23, 2016	Other Postretirement Benefits	
		Pension Benefits Three Months Ended June 30, 2015	Six Months Ended June 30, 2015		Three Months Ended June 30, 2015	Six Months Ended June 30, 2015
<b>Components of net periodic benefit cost:</b>						
Service cost	\$ 12	\$ 14	\$ 28	\$ 1	\$ 1	\$ 3
Interest cost	26	27	54	6	6	12
Expected return on assets	(30)	(35)	(70)	(5)	(5)	(11)
Amortization of:						
Prior service cost (benefit)		1	1	(3)	(3)	(6)
Actuarial loss	14	17	33	2	1	4
<b>Net periodic benefit cost</b>	<b>\$ 22</b>	<b>\$ 24</b>	<b>\$ 46</b>	<b>\$ 1</b>	<b>\$</b>	<b>\$ 2</b>

The amounts below represent Exelon's, Generation's, ComEd's, PECO's, BGE's, Pepco's, DPL's, ACE's, BSC's and PHISCO's allocated portion of 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, 2016 and 2015.

Pension and Other Postretirement Benefit Costs	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Exelon	\$ 160	\$ 160	\$ 297	\$ 317
Generation	55	68	109	133
ComEd	42	51	83	103
PECO	8	10	17	19
BGE	18	17	33	33
BSC <sup>(a)</sup>	10	14	24	29
Pepco <sup>(b)</sup>	7	7	16	15
DPL <sup>(b)</sup>	4	4	9	8
ACE <sup>(b)</sup>	4	4	8	8
PHISCO <sup>(a)(b)</sup>	12	9	21	17

Pension and Other Postretirement Benefit Costs	Successor	Predecessor	Successor	Predecessor
	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	March 24, 2016 to June 30, 2016	January 1, 2016 to March 23, 2016
PHI	\$ 27	\$ 24	\$ 31	\$ 23
				Six Months Ended June 30, 2015
				\$ 48

(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.



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(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.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

(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, 2016 and 2015:

Savings Plan Matching Contributions	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Exelon	\$ 30	\$ 38	\$ 56	\$ 60
Generation	13	20	25	33
ComEd	7	8	13	13
PECO	2	3	4	4
BGE	2	3	3	5
BSC <sup>(a)</sup>	2	4	7	5
Pepco <sup>(b)</sup>	1	1	2	2
DPL <sup>(b)</sup>		1	1	1
PHISCO <sup>(a)(b)</sup>	2	1	3	3
ACE <sup>(b)</sup>	1	1	1	1

Savings Plan Matching Contributions	<i>Successor</i>	<i>Predecessor</i>	<i>Successor</i>	<i>Predecessor</i>	
	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	March 24, 2016 to June 30, 2016	January 1, 2016 to March 23, 2016	Six Months Ended June 30, 2015
PHI	\$ 4	\$ 4	\$ 4	\$ 3	\$ 7

(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.



**Table of Contents****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, 2016 and 2015, Exelon, Generation and ComEd 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 <sup>(a)</sup>	ComEd
<b>Three Months Ended</b>			
June 30, 2016	\$ 2	\$ 1	\$ 1
June 30, 2015	1	1	
<b>Six Months Ended</b>			
June 30, 2016	\$ 4	\$ 3	\$ 1
June 30, 2015	21	21	

(a) The amounts above for Generation include \$1 million and \$2 million for amounts billed by BSC through intercompany allocations for the three months ended June 30, 2016 and 2015, respectively, and \$2 million and \$4 million for the six months ended June 30, 2016 and 2015, respectively. The amounts above for ComEd include less than \$1 million and \$1 million billed by BSC through intercompany allocations for the three and six months ended June 30, 2016, respectively.

**Early Plant Retirement-Related Severance**

As a result of the Clinton and Quad Cities plant retirement decision, Exelon and Generation will incur certain employee-related costs, including severance benefit costs. Severance benefits will be provided to impacted union and non-union employees, to the extent that those employees are not redeployed to other locations. In June 2016, Exelon and Generation recognized severance benefit costs of \$46 million related to expected employee severances resulting from the plant retirements within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income. The final amount of severance cost will ultimately depend on the specific employees severed. The \$46 million of costs for Generation include \$3 million for amounts billed by BSC through intercompany allocations 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.

Upon Senior Management approval of the cost management targets and initiatives in the first quarter of 2016, Exelon recorded severance benefit costs of \$17 million associated with the anticipated position reductions. Additional severance benefit costs recorded in the second quarter were immaterial. The final amount of the charge will ultimately depend on the specific employees severed.

For the six months ended June 30, 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
<b>Six Months Ended June 30, 2016</b>					

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Severance benefits <sup>(a)</sup>	\$ 17	\$ 12	\$ 3	\$ 1	\$ 1
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**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

(a) 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.

**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.

For the three and six months ended June 30, 2016, the Registrants recorded the following severance costs (benefits) 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 <sup>(b)</sup>	DPL <sup>(c)</sup>	ACE	
<b>Three Months Ended June 30, 2016</b>										
Severance benefits <sup>(a)</sup>	\$ 2	\$ (1)	\$ (1)	\$	\$	\$ 4	\$ 2	\$ 1	\$ 1	
<b>Six Months Ended June 30, 2016</b>										
Severance benefits <sup>(a)</sup>	\$ 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.

(b) Pepco established a regulatory asset of \$9 million as of June 30, 2016, primarily for severance benefit costs related to the PHI merger.

(c) DPL established a regulatory asset of \$3 million as of June 30, 2016, primarily for severance benefit costs related to the PHI merger.

**Severance Liability**

Amounts included in the table below represent the severance liability recorded 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, 2015	\$ 35	\$ 23	\$ 3	\$	\$ 1	\$	\$	\$	\$	
Severance charges <sup>(a)(b)</sup>	129	56	1			54	1	1		
Payments	(19)	(4)	(1)			(11)				
Balance at June 30, 2016	\$ 145	\$ 75	\$ 3	\$	\$ 1	\$ 43	\$ 1	\$ 1	\$	

(a)

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Includes salary continuance and health and welfare severance benefits. Amounts primarily represent benefits provided for the PHI post-merger integration, the Clinton and Quad Cities early plant retirements and the cost management program.

(b) Represents activity from March 24, 2016 to June 30, 2016 for PHI, Pepco, DPL and ACE.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**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, 2016 and 2015:

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
<b>Exelon<sup>(a)</sup></b>						
Beginning balance	\$ (19)	\$ 3	\$ (2,565)	\$ (40)	\$ (3)	\$ (2,624)
OCI before reclassifications	(4)		(2)	6	(7)	(7)
Amounts reclassified from AOCI <sup>(b)</sup>	(3)		69			66
Net current-period OCI	(7)		67	6	(7)	59
Ending balance	\$ (26)	\$ 3	\$ (2,498)	\$ (34)	\$ (10)	\$ (2,565)
<b>Generation<sup>(a)</sup></b>						
Beginning balance	\$ (21)	\$ 1	\$	\$ (40)	\$ (3)	\$ (63)
OCI before reclassifications	(1)			6	(4)	1
Amounts reclassified from AOCI <sup>(b)</sup>	(3)					(3)
Net current-period OCI	(4)			6	(4)	(2)
Ending balance	\$ (25)	\$ 1	\$	\$ (34)	\$ (7)	\$ (65)
<b>PECO<sup>(a)</sup></b>						
Beginning balance	\$	\$ 1	\$	\$	\$	\$ 1
OCI before reclassifications						
Amounts reclassified from AOCI <sup>(b)</sup>						
Net current-period OCI						
Ending balance	\$	\$ 1	\$	\$	\$	\$ 1
<b>PHI Predecessor<sup>(a)</sup></b>						
Beginning balance January 1, 2016	\$ (8)	\$	\$ (28)	\$	\$	\$ (36)



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OCI before reclassifications								
Amounts reclassified from AOCI <sup>(b)</sup>				1				1
Net current-period OCI				1				1
Ending balance March 23, 2016 <sup>(c)</sup>	\$	(8)	\$	\$	(27)	\$	\$	\$ (35)

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

Six Months Ended June 30, 2015	Gains and (losses) on Hedging Activity	Unrealized Gains and (losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Equity Investments	Total
<b>Exelon<sup>(a)</sup></b>						
Beginning balance	\$ (28)	\$ 3	\$ (2,640)	\$ (19)	\$	\$ (2,684)
OCI before reclassifications	(10)		(29)	(9)		(48)
Amounts reclassified from AOCI <sup>(b)</sup>	19		87			106
Net current-period OCI	9		58	(9)		58
Ending balance	\$ (19)	\$ 3	\$ (2,582)	\$ (28)	\$	\$ (2,626)
<b>Generation<sup>(a)</sup></b>						
Beginning balance	\$ (18)	\$ 1	\$	\$ (19)	\$	\$ (36)
OCI before reclassifications	(6)	1		(9)		(14)
Amounts reclassified from AOCI <sup>(b)</sup>	3					3
Net current-period OCI	(3)	1		(9)		(11)
Ending balance	\$ (21)	\$ 2	\$	\$ (28)	\$	\$ (47)
<b>PECO<sup>(a)</sup></b>						
Beginning balance	\$	\$ 1	\$	\$	\$	\$ 1
OCI before reclassifications						
Amounts reclassified from AOCI <sup>(b)</sup>						
Net current-period OCI						
Ending balance	\$	\$ 1	\$	\$	\$	\$ 1
<b>PHI Predecessor<sup>(a)</sup></b>						
Beginning balance	\$ (9)	\$	\$ (37)	\$	\$	\$ (46)
OCI before reclassifications						
Amounts reclassified from AOCI <sup>(b)</sup>			4			4
Net current-period OCI			4			4
Ending balance	\$ (9)	\$	\$ (33)	\$	\$	\$ (42)

- (a) All amounts are net of tax. 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, 2016 and 2015. 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, 2016 and 2015.

**Table of Contents****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 <sup>(a)</sup>		Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	Generation	
<b>Amortization of pension and other postretirement benefit plan items</b>			
Prior service costs <sup>(b)</sup>	\$ 19	\$	
Actuarial losses <sup>(b)</sup>	(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 <sup>(a)</sup>			Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	Generation	Predecessor January 1, 2016 to March 23, 2016 PHI	
<b>Gains and (losses) on cash flow hedges</b>				
Other cash flow hedges	\$ 5	\$ 5	\$	Interest expense
Total before tax	5	5		
Tax expense	(2)	(2)		
Net of tax	\$ 3	\$ 3	\$	Comprehensive income
<b>Amortization of pension and other postretirement benefit plan items</b>				
Prior service costs <sup>(b)</sup>	\$ 38	\$	\$	
Actuarial losses <sup>(b)</sup>	(151)		(1)	
Total before tax	(113)		(1)	
Tax benefit	44			

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Net of tax	\$ (69)	\$	\$ (1)	
<b>Total Reclassifications</b>	\$ (66)	\$ 3	\$ (1)	Comprehensive income

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**Three Months Ended June 30, 2015**

Details about AOCI components	Items reclassified out of AOCI <sup>(a)</sup>			Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	Generation	Predecessor PHI	
<b>Gains and (losses) on cash flow hedges</b>				
Other cash flow hedges	\$ (2)	\$ (2)	\$	Interest expense
Total before tax	(2)	(2)		
Tax expense				
Net of tax	\$ (2)	\$ (2)	\$	Comprehensive income
<b>Amortization of pension and other postretirement benefit plan items</b>				
Prior service costs <sup>(b)</sup>	\$ 19	\$	\$	
Actuarial losses <sup>(b)</sup>	(90)		(3)	
Total before tax	(71)		(3)	
Tax expense	27			
Net of tax	\$ (44)	\$	\$ (3)	
<b>Total Reclassifications for the period</b>	<b>\$ (46)</b>	<b>\$ (2)</b>	<b>\$ (3)</b>	<b>Comprehensive income</b>

**Six Months Ended June 30, 2015**

Details about AOCI components	Items reclassified out of AOCI <sup>(a)</sup>			Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	Generation	Predecessor PHI	
<b>Gains and (losses) on cash flow hedges</b>				
Terminated interest rate swaps	\$ (26)	\$	\$	Other, net
Energy related hedges	2	2		Operating revenues
Other cash flow hedges	(5)	(5)		Interest expense
Total before tax	(29)	(3)		
Tax benefit	10			
Net of tax	\$ (19)	\$ (3)	\$	Comprehensive income

<b>Amortization of pension and other postretirement benefit plan items</b>				
Prior service costs <sup>(b)</sup>	\$ 38	\$	\$	
Actuarial losses <sup>(b)</sup>	(180)			(5)
Total before tax	(142)			(5)
Tax benefit	55			1
Net of tax	\$ (87)	\$	\$	(4)
<b>Total Reclassifications</b>	<b>\$ (106)</b>	<b>\$ (3)</b>	<b>\$ (4)</b>	<b>Comprehensive income</b>

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

(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).

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, 2016 and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
<b>Exelon</b>				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	\$ 7	\$ 8	\$ 15	\$ 15
Actuarial loss reclassified to periodic cost	(30)	(35)	(60)	(69)
Pension and non-pension postretirement benefit plans valuation adjustment			1	17
Change in unrealized gain/(loss) on cash flow hedges	2	(2)	4	(6)
Change in unrealized loss on equity investments	1		3	
Change in unrealized gain on marketable securities	(1)	1		1
<b>Total</b>	<b>\$ (21)</b>	<b>\$ (28)</b>	<b>\$ (37)</b>	<b>\$ (42)</b>
<b>Generation</b>				
Change in unrealized gain/(loss) on cash flow hedges	\$ 1	\$ (1)	\$ 3	\$ 1
Change in unrealized loss on equity investments	1		3	
Change in unrealized gain on marketable securities				1
<b>Total</b>	<b>\$ 2</b>	<b>\$ (1)</b>	<b>\$ 6</b>	<b>\$ 2</b>

	Three Months Ended June 30, 2015	Predecessor January 1, 2016 to March 23, 2016	Six Months Ended June 30, 2015
<b>PHI</b>			
Pension and non-pension postretirement benefit plans:			
Actuarial loss reclassified to periodic cost	\$	\$	\$ (1)

**16. Mezzanine Equity (Exelon, Generation and PHI)****Contingently Redeemable Noncontrolling Interests (Exelon and Generation)**

In November 2015, 2015 ESA Investco, LLC, a wholly owned subsidiary of Generation, entered into an arrangement to sell a portion of its equity to a tax equity investor. Pursuant to the operating agreement, in certain circumstances the equity contributed by the noncontrolling interests holder could be contingently redeemable. These circumstances are outside of the control of Generation and the noncontrolling interests holder resulting in a portion of the noncontrolling interests being considered contingently redeemable and thus presented in mezzanine equity on



the consolidated balance sheet.

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

The following table summarizes the changes in the contingently redeemable noncontrolling interests for the six months ended June 30, 2016:

Balance at December 31, 2015	\$ 28
Cash received from noncontrolling interests	52
Release of contingency	(56)
Balance at June 30, 2016	\$ 24

**Preferred Stock (PHI)**

In connection with the PHI Merger Agreement, Exelon purchased 18,000 originally issued shares of PHI preferred stock for a purchase price of \$180 million. PHI excluded the preferred stock from equity at December 31, 2015 since the preferred stock contained conditions for redemption that were not solely within the control of PHI. Management determined that 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 shares of the preferred stock in the event of such a termination were separately accounted for as derivatives. As of December 31, 2015, the fair value of the derivative related to the preferred stock was estimated to be \$18 million based on PHI's updated assessment and was included in Current assets with a corresponding increase in Preferred stock on PHI's Consolidated Balance Sheet. Immediately prior to the merger date, PHI updated its assessment of the fair value of the derivative and reduced the fair value to zero, recording the \$18 million decrease in fair value as a reduction of Other, within PHI's predecessor period, January 1, 2016 to March 23, 2016, Statement of Operations and Comprehensive Income.

On March 23, 2016, the preferred stock was cancelled and the \$180 million cash consideration previously received by PHI to issue the preferred stock was treated as additional merger purchase price consideration.

**17. Earnings Per Share and Equity (Exelon and BGE)****Earnings per Share (Exelon)**

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,	
	2016	2015	2016	2015
<b>Exelon</b>				
Net income attributable to common shareholders	\$ 267	\$ 638	\$ 440	\$ 1,331
Weighted average common shares outstanding - basic	924	863	923	862
Assumed exercise and/or distributions of stock-based awards	2	3	3	4

Weighted average common shares outstanding	diluted	926	866	926	866
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**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 11 million and 12 million for the three and six months ended June 30, 2016, respectively and 13 million and 15 million for three and six months ended June 30, 2015, respectively. 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, respectively, and 1 million for the three and six months ended June 30, 2015. Refer to Note 19 Shareholder's Equity of the Exelon 2015 Form 10-K for further information regarding the equity units.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of \$2.3 billion as of June 30, 2016. In 2008, Exelon management decided to defer indefinitely any share repurchases.

***Preference Stock Redemption (BGE)***

BGE has \$190 million of cumulative preference stock that are redeemable at its option at any time for the redemption price of \$100 per share, plus accrued and unpaid dividends. On July 3, 2016, BGE redeemed all 400,000 shares of its outstanding 7.125% Cumulative Preference Stock, 1993 Series and all 600,000 shares of its outstanding 6.99% Cumulative Preference Stock, 1995 Series for \$100 million, plus accrued and unpaid dividends. Following these redemptions, BGE has \$90 million of cumulative preference stock outstanding.

**18. Commitments and Contingencies (All Registrants)**

The following is an update to the current status of commitments and contingencies set forth in Note 23 of the Exelon 2015 Form 10-K and Note 16 of the PHI 2015 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 estimate includes \$95 million to \$120 million relating to the construction of a headquarters building in Baltimore for Generation's competitive energy businesses.

The direct investment commitment also includes \$500 million to \$600 million relating to Exelon and Generation's development or assistance in the development of 275-300 MWs of new generation in Maryland, which is expected to be completed over a period of 10 years. As of June 30, 2016, Exelon and Generation have incurred \$402 million towards satisfying the commitment for new generation development in the state of Maryland, with approximately 220 MW of the new generation commencing with commercial operations to date. 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 expect that the majority of these commitments will be satisfied by building or acquiring generating assets and, therefore, will be primarily capital in nature and recognized as incurred. However, during the third quarter of 2014, the conditions associated with one of the generation development commitments changed such that Exelon and Generation believe that the most likely outcome will involve making subsidy payments and/or liquidated damages payments rather than constructing the specified generating plant. As a result, Exelon and Generation recorded a pre-tax \$44 million loss contingency

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related to this generation development commitment. While this \$44 million loss contingency represents Generation's best estimate of the future obligation, it is reasonably possible that Exelon and Generation could ultimately be required to make cumulative subsidy payments of up to a maximum of approximately \$105 million over a 20-year period dependent on actual generating output from a successfully constructed generating plant.

**Equity Investment Commitments (Exelon and Generation)**

Generation has entered 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. The commitments include approximately \$20 million of in-kind services and 100% of 2015 ESA Investco, LLC's equity commitment since 2015 ESA Investco, LLC is consolidated by Generation (see Note 3 Variable Interest Entities for additional details). As of June 30, 2016, Generation's estimated commitments relating to its equity purchase agreements, including the in-kind services contributions, is anticipated to be as follows:

	<b>Total</b>
2016 <sup>(a)</sup>	\$ 203
2017	22
2018	10
<b>Total</b>	<b>\$ 235</b>

(a) The noncontrolling interests holder of 2015 ESA Investco, LLC will contribute up to \$90 million in support of a portion of the remaining equity commitment.

**Commercial Commitments (All Registrants)**

The Registrants' commercial commitments as of June 30, 2016, representing commitments potentially triggered by future events were as follows:

	<b>Exelon</b>	<b>Generation</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>	<i>Successor</i> <b>PHI</b>	<b>Pepco</b>	<b>DPL</b>	<b>ACE</b>
Letters of credit (non-debt) <sup>(a)</sup>	\$ 1,651	\$ 1,580	\$ 16	\$ 23	\$ 2	\$ 1	\$ 1	\$ 1	\$ 1
Surety bonds <sup>(b)</sup>	1,055	964	10	9	10	16	9	4	3
Financing trust guarantees	628		200	178	250				
Nuclear insurance premiums <sup>(c)</sup>	3,045	3,045							
Guaranteed lease residual values <sup>(d)</sup>	20					20	5	7	5
<b>Total commercial commitments</b>	<b>\$ 6,399</b>	<b>\$ 5,589</b>	<b>\$ 226</b>	<b>\$ 210</b>	<b>\$ 262</b>	<b>\$ 37</b>	<b>\$ 14</b>	<b>\$ 11</b>	<b>\$ 9</b>

(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)

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- Nuclear insurance premiums Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site, including CENG sites, under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.
- (d) 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 \$50 million, \$13 million of

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

which is a guarantee by Pepco, \$16 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, 2016, 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. An inflation adjustment must be made at least once every 5 years and the last inflation adjustment was made 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. As of June 30, 2016, the amount of nuclear energy liability insurance purchased is \$375 million for each operating site. Additionally, the Price-Anderson Act requires a second layer of protection through the mandatory participation in a retrospective rating plan for power reactors (currently 102 reactors) resulting in an additional \$13.0 billion 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. Under the Price-Anderson Act, the maximum assessment in the event of an incident for each nuclear operator, per reactor, per incident (including a 5% surcharge), is \$127.3 million, payable at no more than \$19 million per reactor per incident per year. Exelon's maximum liability per incident is approximately \$2.7 billion, including CENG's related liability.

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 2015 Form 10-K for additional information on Generation's operations relating to CENG.

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

NEIL 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

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

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 for all losses by all insureds 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, 17 of which the remediation has been completed and approved by the Illinois EPA or the U.S. EPA and 25 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 2020.

PECO has identified 26 sites, 16 of which have been remediated in accordance with applicable PA DEP regulatory requirements. The remaining 10 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 2021.

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 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. One former gas purification site is currently under investigation at the direction of the MDE. 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





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received recovery of actual clean-up costs in distribution rates. DPL has historically received recovery of actual clean-up costs in distribution rates.

As of June 30, 2016 and December 31, 2015, 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:

<b>June 30, 2016</b>	<b>Total Environmental Investigation and Remediation Reserve</b>	<b>Portion of Total Related to MGP Investigation and Remediation<sup>(a)</sup></b>
Exelon	\$ 410	\$ 311
Generation	66	
ComEd	277	275
PECO	35	33
BGE	2	2
PHI (Successor)	30	1
Pepco	27	
DPL	2	1
ACE	1	

<b>December 31, 2015</b>	<b>Total Environmental Investigation and Remediation Reserve</b>	<b>Portion of Total Related to MGP Investigation and Remediation<sup>(a)</sup></b>
Exelon	\$ 369	\$ 301
Generation	63	
ComEd	266	264
PECO	37	35
BGE	3	2
PHI (Predecessor)	33	1
Pepco	24	
DPL	3	1
ACE	1	

(a) For BGE, includes reserve for Riverside, a gas purification site. See discussion below for additional information.

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.



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**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)*****Water Quality***

***Groundwater Contamination.*** In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third-party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a \$1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. Generation's remaining groundwater contamination reserve was approximately \$11 million at June 30, 2016 and \$12 million at December 31, 2015.

***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 site, including the Pepco Energy Services generating facility previously located on the site that was deactivated in 2012 and subsequently demolished. 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 as determined by EPA to be necessary to meet the applicable District of Columbia surface water quality standards. The permit contemplated that Pepco would meet these limits over time through the use of best management practices (BMPs). As of December 2012, Pepco completed the implementation of the first two phases of BMPs identified in a plan approved by EPA (consisting principally of installing metal absorbing filters to capture contaminants at storm water inlets, removing stored equipment from areas exposed to the weather, covering and painting exposed metal pipes, and covering and cleaning dumpsters). These measures were effective in reducing metal concentrations in storm water discharges, but were not sufficient to meet all of the numerical limits for metals. Most of the quarterly monitoring results since the issuance of the permit have shown exceedances of the limits for copper and zinc, as well as occasional exceedances for iron and lead.

The NPDES permit was due to expire on June 19, 2014. Pepco submitted a permit renewal application on December 17, 2013. In November 2014, EPA advised Pepco that it will not renew the permit until the Benning Road site has come into compliance with the existing permit limits. The current permit remains in effect pending EPA's action on the renewal application. In December 2014, Pepco submitted a plan to EPA to implement the third phase of BMPs recommended in the original permit compliance plan with the objective of achieving full compliance with the permit limits for metals by the end of 2015 and Pepco immediately began to implement the additional BMPs in accordance with the plan. On September 1, 2015, Pepco submitted a report to EPA on the status of implementation of the third phase of BMPs. As of that date, Pepco had fully implemented most of the elements of the Phase 3 plan, including installation of upgraded storm water inlet controls (filters and booms), enhanced inspection and maintenance of inlets, removal of materials and equipment from exposure to storm water, and removal of accumulated sediments from the underground storm drains. The sampling results from the third quarter of 2015 showed compliance with all of the permit limits. However, more recent sampling results continued to show modest exceedances for copper and zinc. As confirmed by this latest sampling, because the permit limits are low and site conditions are subject to variation, Pepco has concluded that some form of storm water treatment prior to discharge will be necessary to ensure ongoing compliance with all permit limits and has begun the process of evaluating treatment options. The nature and scope of the necessary treatment system, and the amount of the associated capital expenditures, will not be known until Pepco has completed the evaluation and design process.

Pepco has been engaged in discussions with representatives from EPA and the DOJ regarding permit compliance. On October 30, 2015, EPA filed a Clean Water Act civil enforcement action against Pepco in federal district court. Pepco expects that this enforcement action will be resolved through a consent decree that will (i) establish further requirements to achieve compliance with the permit limits, including the design and installation of an appropriate storm water treatment system as noted above, and (ii) include civil penalties for past noncompliance. Pepco has established what it believes is an appropriate reserve for potential penalties which is

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

included in the table above. Pepco does not expect the amount of such penalties above the financial reserve to have a material adverse effect on Exelon's, PHI's and Pepco's consolidated financial condition, results of operations or cash flows.

Pepco and EPA are currently in discussions regarding the terms of the contemplated consent decree, and it is anticipated that the parties will finalize the consent decree before the end of 2016. In response to a joint motion by the parties, the court has extended the deadline for Pepco to answer the complaint to August 15, 2016, to give the parties time to work towards agreement on the terms of a consent decree. The parties contemplate seeking a further extension if necessary to complete their negotiations. Once executed by the parties, the consent decree will be filed with the court for review and approval following a period for public comment.

On March 14, 2016, the court granted a motion by the Anacostia Riverkeeper to intervene in this case as a plaintiff along with EPA. As an intervenor, the Anacostia Riverkeeper will be entitled to file a brief commenting on the proposed consent decree and to appeal any decision by the court to approve the consent decree over the Anacostia Riverkeeper's objection, but its participation is not expected to materially affect the progress or outcome of the consent decree negotiations.

***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. On February 18, 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 \$60 million, 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. 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 final 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 are now scheduled to be completed in fall of 2016 to enable the EPA to propose a remedy for public comment by the end of 2016. Thereafter the EPA will select a final remedy and 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, but does not have a basis to establish a reasonable estimate of the range of costs. 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 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

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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). Such legislation would become final upon passage in the U.S. House of Representatives and the signature of the President, and be subject to annual funding appropriations in the U.S. Budget. Remediation under FUSRAP would not alter the liability of the PRPs, but could 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 2017 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.

Commencing in February 2012, 57 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, and Cotter, which remains a defendant. The suits allege that individuals living in the North St. Louis area developed some form of cancer due to Cotter's negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price-Anderson Act. The complaints do not contain specific damage claims. In the event of a finding of liability, it is reasonably possible that Exelon would be considered liable due to its indemnification responsibilities of Cotter described above. The court has dismissed the lawsuits filed by 30 of the plaintiffs. 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.

**68<sup>th</sup> 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 March 2004, BGE and other PRPs formed the 68th Street Coalition and entered into consent order negotiations with the EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the EPA and 19 of the PRPs, including BGE, with respect to investigation of the site became

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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. Although the investigation and options provided to the EPA are still subject to EPA review and selection of a remedy, the range of estimated clean-up costs to be allocated among all of the PRPs is in the range of \$50 million to \$64 million. 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. A wholly owned subsidiary of Generation has agreed to indemnify BGE for most of the costs related to this settlement and clean-up of the site. Based on Generation's preliminary review, it appears probable that Generation has liability and has established an appropriate accrual which are included in the table above for its share of the estimated clean-up costs.

**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). 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. Generation currently estimates the remaining cost to close the site to be approximately \$7 million which has been fully reserved and included in the table above as of June 30, 2016.

**Sauer Dump.** On May 30, 2012, BGE was notified by the EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, Maryland. The EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. In addition, the 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 EPA which requires the PRPs to conduct a remedial investigation (RI) and feasibility study (FS) at the site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The ultimate outcome of this proceeding is uncertain. Since the EPA has not selected a cleanup remedy and the allocation of the cleanup costs among the PRPs has not been determined, BGE can not estimate the range of loss.

**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 of three specific areas of the site, and 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 on June 2, 2015. On November 3, 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. 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.

**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

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portion of the site consists of a Pepco transmission and distribution service center that remains in operation. The principal contaminants allegedly of concern are polychlorinated biphenyls and polycyclic aromatic hydrocarbons. In December 2011, the U.S. District Court for the District of Columbia approved a consent decree entered into by Pepco and Pepco Energy Services with the DOEE, which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10 to 15 acre portion of the adjacent Anacostia River. 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 addition, in conjunction with the power plant demolition activities, Pepco and Pepco Energy Services collected soil samples adjacent to and beneath the concrete basins for the dismantled cooling towers for the generating facility. This sampling showed localized areas of soil contamination associated with the cooling tower basins, and, beginning in the third quarter of 2016, Pepco and Pepco Energy Services expect to implement a plan approved by DOEE to remove contaminated soil in conjunction with the demolition and removal of the concrete basins. On April 30, 2015, Pepco and Pepco Energy Services submitted a draft RI Report to DOEE. After review, DOEE determined that additional field investigation and data analysis is required to complete the RI process (much of which is 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 on February 29, 2016. The additional field investigation and data analysis will proceed later in 2016 according to a schedule to be developed by Pepco and Pepco Energy Services and approved by DOEE. 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 with an FS to evaluate possible remedial alternatives. This effort also may include a treatability study to evaluate the effectiveness of potential remedial options. Once the FS evaluation has been completed, Pepco and Pepco Energy Services will prepare and submit a draft FS Report for review and comment by DOEE and the public. Thereafter, Pepco and Pepco Energy Services will revise the draft FS Report as appropriate to address comments received and will submit a final FS Report to DOEE.

Upon DOEE's approval of the final remedial investigation and feasibility study 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 based on the results of the remedial investigation and feasibility study. 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 reserves 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 has 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. On March 18, 2016, DOEE released a draft of the river-wide RI Report for public



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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. At this time, it is not possible to predict the nature or extent of Pepco's possible participation in the river-wide RI/FS process, or its potential exposure for response costs beyond those associated with the Benning RI/FS component of the river-wide initiative.

**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 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 has assumed responsibility for performing the ISRA-required remediation and for the payment of all related ISRA compliance costs up to \$10 million. PHI is 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 located in New Jersey are in the range of approximately \$7 million to \$18 million, and PHI has established an appropriate accrual for its share of the estimated clean-up costs, which is included in the table above.

**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.

**Peck Iron and Metal Site.** EPA informed Pepco in a May 2009 letter that Pepco may be a PRP under CERCLA with respect to the cleanup of the Peck Iron and Metal site in Portsmouth, Virginia, and for costs EPA has incurred in cleaning up the site. The EPA letter states that Peck Iron and Metal purchased, processed, stored and shipped metal scrap from military bases, governmental agencies and businesses and that the Peck Iron and

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Metal scrap operations resulted in the improper storage and disposal of hazardous substances. EPA bases its allegation on its belief that Pepco was a customer at the site. Pepco has advised EPA by letter that its records show no evidence of any sale of scrap metal by Pepco to the site. Even if EPA has such records and such sales did occur, Pepco believes that any such scrap metal sales may be entitled to the recyclable material exemption from CERCLA liability. In September 2011, EPA initiated a RI/FS for the site using Federal funds. Pepco cannot at this time estimate an amount or range of reasonably possible loss associated with this RI/FS, any remediation activities to be performed at the site or any other costs that EPA might seek to impose on Pepco.

**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. 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, 2016 and December 31, 2015, Generation had reserved approximately \$85 million and \$95 million, respectively, in total for asbestos-related bodily injury claims. As of June 30, 2016, approximately \$22 million of this amount related to 226 open claims presented to Generation, while the remaining \$63 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. During the second quarter of 2016, Generation decreased its reserve by approximately \$8 million, primarily attributable to a continued decline in expected claims activity.

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 2 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.

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

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.

Approximately 449 individuals who were never employees of BGE or certain Constellation subsidiaries have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and certain Constellation subsidiaries in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or certain Constellation subsidiaries and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation's financial results.

Discovery begins in these cases after they are placed on the trial docket. Given the limited discovery in these cases, BGE and Generation do not know the specific facts that are necessary to provide an estimate of the reasonably possible loss relating to these claims; as such, no accrual has been made and a range of loss is not estimable. The specific facts not known include:

the identity of the facilities at which the plaintiffs allegedly worked as contractors;

the names of the plaintiffs' employers;

the dates on which and the places where the exposure allegedly occurred; and

the facts and circumstances relating to the alleged exposure.

Insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions.

***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, 2016 and December 31, 2015, ComEd

did not have any material liabilities recorded for these storm events.

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

***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.

***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. Generation is reviewing the decision and determining whether to appeal to the Delaware Supreme Court. Generation has accrued an amount to cover its potential liability.

***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.

***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.

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

**19. 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, 2016 and 2015:

	Three Months Ended June 30, 2016								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
<b>Other, Net</b>									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds <sup>(a)</sup>									
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 <sup>(b)</sup>	(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

	Six Months Ended June 30, 2016									Successor	Predecessor
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI	PHI	March 24, 2016 to June 30, 2016
<b>Other, Net</b>											
Decommissioning-related activities:											
Net realized income on decommissioning trust funds <sup>(a)</sup>											
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									
	(211)	(211)									

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Regulatory offset to decommissioning trust fund-related activities <sup>(b)</sup>										
Total decommissioning-related activities	206	206								
Investment income (expense)	12	5	(1)	2 <sup>(c)</sup>						
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)

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

	Three Months Ended June 30, 2015								
	Exelon	Generation	ComEd	PECO	BGE	Predecessor PHI	Pepco	DPL	ACE
<b>Other, Net</b>									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds <sup>(a)</sup>									
Regulatory agreement units	\$ 93	\$ 93	\$	\$	\$	\$	\$	\$	\$
Non-regulatory agreement units	74	74							
Net unrealized losses on decommissioning trust funds									
Regulatory agreement units	(133)	(133)							
Non-regulatory agreement units	(96)	(96)							
Regulatory offset to decommissioning trust fund-related activities <sup>(b)</sup>	28	28							
Total decommissioning-related activities	(34)	(34)							
Investment income (expense)	1			(1)	1 <sup>(c)</sup>				
Long-term lease income	4								
AFUDC Equity	5		1	1	3	3	3		
Other	7	3	4	1		9	5	2	1
Other, net	\$ (17)	\$ (31)	\$ 5	\$ 1	\$ 4	\$ 12	\$ 8	\$ 2	\$ 1

	Six Months Ended June 30, 2015								
	Exelon	Generation	ComEd	PECO	BGE	Predecessor PHI	Pepco	DPL	ACE
<b>Other, Net</b>									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds <sup>(a)</sup>									
Regulatory agreement units	\$ 164	\$ 164	\$	\$	\$	\$	\$	\$	\$
Non-regulatory agreement units	104	104							
Net unrealized losses on decommissioning trust funds									
Regulatory agreement units	(85)	(85)							
Non-regulatory agreement units	(56)	(56)							
Net unrealized gains on pledged assets									
Zion Station decommissioning	9	9							
Regulatory offset to decommissioning trust fund-related activities <sup>(b)</sup>	(78)	(78)							
Total decommissioning-related activities	58	58							
Investment income (expense)	4	1		(1)	2 <sup>(c)</sup>				
Long-term lease income	8								
Interest income related to uncertain income tax positions		1							
AFUDC Equity	11		1	3	7	7	6		1
Terminated interest rate swaps <sup>(d)</sup>	(26)								
Other	9	2	8	1	(1)	14	7	5	2
Other, net	\$ 64	\$ 62	\$ 9	\$ 3	\$ 8	\$ 21	\$ 13	\$ 5	\$ 3



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- (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 2015 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
- (c) Relates to the cash return on BGE's rate stabilization deferral. See Note 3 Regulatory Matters of the Exelon 2015 Form 10-K for additional information regarding the rate stabilization deferral.
- (d) In January 2015, in connection with Generation's \$750 million issuance of five-year Senior Unsecured Notes, Exelon terminated certain floating-to-fixed interest rate swaps. As the original forecasted transactions were a series of future interest payments over a ten year period, a portion of the anticipated interest payments were probable not to occur. As a result, \$26 million of anticipated payments were reclassified from AOCI to Other, net in Exelon's Consolidated Statement of Operations and Comprehensive Income.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**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, 2016 and 2015:

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

	Six Months Ended June 30, 2015									
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	Predecessor	PHI
<b>Depreciation, amortization, accretion and depletion</b>										
Property, plant and equipment <sup>(a)</sup>	\$ 1,087	\$ 485	\$ 312	\$ 119	\$ 143	\$ 193	\$ 81	\$ 50	\$ 38	
Amortization of regulatory assets <sup>(a)</sup>	101		40	12	49	114	44	24	48	
Amortization of intangible assets, net <sup>(a)</sup>	24	24								
Amortization of energy contract assets and liabilities <sup>(b)</sup>			1							
Nuclear fuel <sup>(c)</sup>	552	552								
ARO accretion <sup>(d)</sup>	193	193								
Total depreciation, amortization, accretion and depletion	\$ 1,957	\$ 1,255	\$ 352	\$ 131	\$ 192	\$ 307	\$ 125	\$ 74	\$ 86	

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

(b)

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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.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

	Six Months Ended June 30, 2016								Successor Predecessor	
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	March 24, 2016 to June 30, 2016 PHI	January 1, 2016 to March 23, 2016 PHI
<b>Other non-cash operating activities:</b>										
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 <sup>(a)</sup>	(123)	(123)								
Energy-related options <sup>(b)</sup>	(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 <sup>(c)</sup>	(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 <sup>(d)(e)</sup>	503	3				138	100	120	358	
Severance costs	122	50							54	
Asset retirement costs							4	2		
Lower of cost or market inventory adjustment	36	36								
Other	17	17	(3)	(2)	(12)	(4)	(3)	(3)	(7)	(3)
<b>Total other non-cash operating activities</b>	<b>\$ 1,056</b>	<b>\$ 169</b>	<b>\$ 83</b>	<b>\$ 27</b>	<b>\$ 60</b>	<b>\$ 158</b>	<b>\$ 121</b>	<b>\$ 138</b>	<b>\$ 444</b>	<b>\$ 46</b>
<b>Non-cash investing and financing activities:</b>										
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 <sup>(d)(f)</sup>		119								
Fair value of net assets distributed to Exelon in connection with the PHI Merger, net of cash <sup>(d)(f)</sup>									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 <sup>(g)</sup>			5							
Non-cash financing of capital projects	60	60								

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

	Six Months Ended June 30, 2015								
	Exelon	Generation	ComEd	PECO	BGE	Predecessor PHI	Pepco	DPL	ACE
<b>Other non-cash operating activities:</b>									
Pension and non-pension postretirement benefit costs	\$ 317	\$ 133	\$ 103	\$ 19	\$ 33	\$ 48	\$ 15	\$ 8	\$ 8
Loss from equity method investments	2	3							
Provision for uncollectible accounts	80	11	35	24	11	30	9	12	9
Stock-based compensation costs	79					6			
Other decommissioning-related activity <sup>(a)</sup>	(50)	(50)							
Energy-related options <sup>(b)</sup>	27	27							
Amortization of regulatory asset related to debt costs						2	1		
Amortization of rate stabilization deferral	40				40	9	8	1	
Amortization of debt fair value adjustment	(37)	(6)							
Discrete impacts from EIMA <sup>(c)</sup>	77		77						
Amortization of debt costs	35	8	2	1	1	1			
Provision for excess and obsolete inventory						1			
Lower of cost or market inventory adjustment	13	13							
Other	(4)	(5)	5	1	(9)	4		1	
Total other non-cash operating activities	\$ 579	\$ 134	\$ 222	\$ 45	\$ 76	\$ 101	\$ 33	\$ 22	\$ 17
<b>Non-cash investing and financing activities:</b>									
Indemnification of like-kind exchange position <sup>(g)</sup>			3						
Long-term software licensing agreement <sup>(f)</sup>	95								

(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 2015 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, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 5 Regulatory Matters for more information.

(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.

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

**Supplemental Balance Sheet Information**

The following tables provide additional information about assets and liabilities of the Registrants as of June 30, 2016 and December 31, 2015:

June 30, 2016	Exelon	Generation	ComEd	PECO	BGE	Successor				
						PHI	Pepco	DPL	ACE	
<b>Property, plant and equipment:</b>										
Accumulated depreciation and amortization	\$ 17,340 <sup>(a)</sup>	\$ 9,179 <sup>(a)</sup>	\$ 3,785	\$ 3,185	\$ 3,161	\$ 83	\$ 2,995	\$ 1,157	\$ 998	
<b>Accounts receivable:</b>										
Allowance for uncollectible accounts	\$ 314	\$ 82	\$ 74	\$ 75	\$ 33	\$ 50	\$ 16	\$ 17	\$ 17	
December 31, 2015	Exelon	Generation	ComEd	PECO	BGE	Predecessor				
						PHI	Pepco	DPL	ACE	
<b>Property, plant and equipment:</b>										
Accumulated depreciation and amortization	\$ 16,375 <sup>(b)</sup>	\$ 8,639 <sup>(b)</sup>	\$ 3,710	\$ 3,101	\$ 3,016	\$ 5,341	\$ 2,929	\$ 1,139	\$ 968	
<b>Accounts receivable:</b>										
Allowance for uncollectible accounts	\$ 284	\$ 77	\$ 75	\$ 83	\$ 49	\$ 56	\$ 17	\$ 17	\$ 17	

(a) Includes accumulated amortization of nuclear fuel in the reactor core of \$2,936 million.

(b) Includes accumulated amortization of nuclear fuel in the reactor core of \$2,861 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 \$16 million and \$15 million as of June 30, 2016 and December 31, 2015, 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 2015 Form 10-K. The allowance for uncollectible accounts balance associated with these receivables at June 30, 2016 of \$16 million consists of \$1 million, \$3 million and \$12 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2015 of \$15 million consists of \$1 million, \$3 million and \$11 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, 2016 and December 31, 2015 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 2015 Form 10-K.

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**20. 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 power marketing 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:



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South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, 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,

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

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 power marketing activities and allocate resources based on revenue 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 not included in 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.

**Table of Contents****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, 2016 and 2015 is as follows:

**Three Months Ended June 30, 2016 and 2015**

	<i>Successor</i>							
	Generation <sup>(a)</sup>	ComEd	PECO	BGE	PHI <sup>(b)</sup>	Other <sup>(c)</sup>	Intersegment Eliminations	Exelon
<b>Operating revenues<sup>(d)</sup>:</b>								
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)
2015								
Competitive businesses electric revenues	\$ 3,663	\$	\$	\$	\$	\$	\$ (151)	\$ 3,512
Competitive businesses natural gas revenues	431							431
Competitive businesses other revenues	138						(1)	137
Rate-regulated electric revenues		1,148	582	541			(1)	2,270
Rate-regulated natural gas revenues			79	87			(1)	165
Shared service and other revenues						340	(341)	(1)
<b>Intersegment revenues<sup>(e)</sup>:</b>								
2016	\$ 355	\$ 3	\$ 2	\$ 4	\$ 10	\$ 398	\$ (771)	\$ 1
2015	152	1		1		340	(493)	1
<b>Net income (loss):</b>								
2016	\$ 28	\$ 145	\$ 100	\$ 34	\$ 52	\$ (52)	\$ (1)	\$ 306
2015	390	99	70	47		28	(1)	633
<b>Total assets:</b>								
June 30, 2016	\$ 46,897	\$ 28,105	\$ 10,586	\$ 8,325	\$ 20,921	\$ 10,069	\$ (12,125)	\$ 112,778
December 31, 2015	46,529	26,532	10,367	8,295		15,389	(11,728)	95,384

(a) Generation includes the six power marketing 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, 2016 include revenue from sales to PECO of \$64 million and sales to BGE of \$135 million in the Mid-Atlantic region, and sales to ComEd of \$13 million in the Midwest region. For the three months ended June 30, 2015, intersegment revenues for Generation include revenue from sales to PECO of \$49 million and sales to BGE of \$97 million in the Mid-Atlantic region, and sales to ComEd of \$6 million in the Midwest region. For the Successor period of three months ended June 30, 2016, intersegment revenues for Generation include revenue from sales to Pepco of \$88 million, sales to DPL of \$43 million, and sales to ACE of \$12 million in the Mid-Atlantic region.

(b) Amounts included represent activity for the PHI s successor period, three months ended June 30, 2016. PHI includes the three reportable segments: Pepco, DPL and ACE. See tables below for PHI s predecessor periods, including Pepco, DPL and ACE, for January 1, 2016 to March 23, 2016 and for the six months ended June 30, 2015.

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



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

- (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 19 - Supplemental Financial Information for total utility taxes for the three months ended June 30, 2016 and 2015.
- (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.

**Generation total revenues:**

	Three Months Ended June 30, 2016			Three Months Ended June 30, 2015		
	Revenues from external customers <sup>(a)</sup>	Intersegment revenues	Total Revenues	Revenues from external customers <sup>(a)(c)</sup>	Intersegment revenues <sup>(c)</sup>	Total Revenues <sup>(c)</sup>
Mid-Atlantic	\$ 1,432	\$ (16)	\$ 1,416	\$ 1,364	\$ (18)	\$ 1,346
Midwest	1,076	7	1,083	1,206		1,206
New England	352	(1)	351	367		367
New York	356	(10)	346	222	(4)	218
ERCOT	207		207	194	(2)	192
Other Power Regions	232	(9)	223	310	(21)	289
<b>Total Revenues for Reportable Segments</b>	<b>3,655</b>	<b>(29)</b>	<b>3,626</b>	<b>3,663</b>	<b>(45)</b>	<b>3,618</b>
Other <sup>(b)</sup>	(66)	29	(37)	569	45	614
<b>Total Generation Consolidated Operating Revenues</b>	<b>\$ 3,589</b>	<b>\$</b>	<b>\$ 3,589</b>	<b>\$ 4,232</b>	<b>\$</b>	<b>\$ 4,232</b>

- (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. Also includes a \$9 million decrease and \$17 million decrease to revenues for the amortization of intangible assets related to commodity contracts recorded at fair value for the three months ended June 30, 2016 and 2015, respectively, unrealized mark-to-market losses of \$615 million and gains of \$25 million for the three months ended June 30, 2016 and 2015, respectively, and elimination of intersegment revenues.
- (c) Exelon corrected an error in the June 30, 2015 balances within Intersegment Revenue and Revenue from external customers for an overstatement of \$46 million of Intersegment Revenue for Reportable Segments for the three months ended June 30, 2015, an understatement of Revenue from external customers for Reportable Segments of \$46 million for the three months ended June 30, 2015, an understatement of \$46 million of Intersegment Revenue for Other for the three months ended June 30, 2015, and an overstatement of Revenue from external customers for Other of \$46 million for the three months ended June 30, 2015. This error is not considered material to any prior period, and there is no impact to Total Revenues.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**Generation total revenues net of purchased power and fuel expense:**

	Three Months Ended June 30, 2016			Three Months Ended June 30, 2015		
	RNF from external customers <sup>(a)</sup>	Intersegment RNF	Total RNF	RNF from external customers <sup>(a)(c)</sup>	Intersegment RNF <sup>(c)</sup>	Total RNF <sup>(c)</sup>
Mid-Atlantic	\$ 830	\$ (2)	\$ 828	\$ 891	\$ 1	\$ 892
Midwest	724	4	728	750	(5)	745
New England	118	(8)	110	95	(7)	88
New York	270	(3)	267	138	7	145
ERCOT	111	(34)	77	91	(21)	70
Other Power Regions	123	(27)	96	113	(51)	62
<b>Total Revenues net of purchased power and fuel for Reportable Segments</b>	<b>2,176</b>	<b>(70)</b>	<b>2,106</b>	<b>2,078</b>	<b>(76)</b>	<b>2,002</b>
Other <sup>(b)</sup>	(164)	70	(94)	305	76	381
<b>Total Generation Revenues net of purchased power and fuel expense</b>	<b>\$ 2,012</b>	<b>\$</b>	<b>\$ 2,012</b>	<b>\$ 2,383</b>	<b>\$</b>	<b>\$ 2,383</b>

(a) Includes purchases and sales from 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. Also includes a \$12 million decrease and a \$14 million decrease to RNF for the amortization of intangible assets related to commodity contracts for the three months ended June 30, 2016 and 2015, respectively, unrealized mark-to-market losses of \$304 million and gains of \$235 million for the three months ended June 30, 2016 and 2015, respectively, accelerated nuclear fuel amortization associated with nuclear decommissioning as discussed at Note 7 Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements of \$9 million for the three months ended June 30, 2016, and the elimination of intersegment revenue net of purchased power and fuel expense.

(c) Exelon corrected an error in the June 30, 2015 balances within Intersegment RNF and RNF from external customers for an understatement of \$6 million of Intersegment RNF for Reportable Segments for the three months ended June 30, 2015, and an overstatement of \$6 million of Intersegment RNF for Other for the three months ended June 30, 2015. This also included an understatement of total RNF for Reportable Segments and an overstatement of total RNF for Other of \$6 million for the three months ended June 30, 2015. The error is not considered material to any prior period, and there is no net impact to Generation Total RNF for 2015.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**Successor and Predecessor PHI:**

		Pepco	DPL	ACE	Other <sup>(b)</sup>	Intersegment Eliminations	PHI
<b>Operating revenues<sup>(a)</sup>:</b>							
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
Three months ended June 30, 2015	Predecessor						
Rate-regulated electric revenues		\$ 504	\$ 246	\$ 285	\$ 59	\$	\$ 1,094
Rate-regulated natural gas revenues			25				25
Shared service and other revenues							
<b>Intersegment revenues<sup>(e)</sup>:</b>							
Three months ended June 30, 2016	Successor	\$ 1	\$ 2	\$ 1	\$ 10	\$ (4)	\$ 10
Three months ended June 30, 2015	Predecessor	1	2	1		(4)	
<b>Net income (loss):</b>							
Three months ended June 30, 2016	Successor	\$ 49	\$ 12	\$ 3	\$ (22)	\$ 10	\$ 52
Three months ended June 30, 2015	Predecessor	42	8	6	(3)		53
<b>Total assets:</b>							
June 30, 2016	Successor	\$ 7,099	\$ 3,971	\$ 3,461	\$ 11,042	\$ (4,652)	\$ 20,921
December 31, 2015	Predecessor	6,908	3,969	3,387	7,162	(5,238)	16,188

(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 19 - Supplemental Financial Information for total utility taxes for the three months ended June 30, 2016 and 2015.

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

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

Six Months Ended June 30, 2016 and 2015

	<i>Successor</i>						<b>Intersegment</b>	
	<b>Generation<sup>(a)</sup></b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>	<b>PHI<sup>(b)</sup></b>	<b>Other<sup>(c)</sup></b>	<b>Eliminations</b>	<b>Exelon</b>
<b>Operating revenues<sup>(d)</sup>:</b>								
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)	
2015								
Competitive businesses electric revenues	\$ 8,059	\$	\$	\$	\$	\$	\$ (360)	\$ 7,699
Competitive businesses natural gas revenues	1,555							1,555
Competitive businesses other revenues	460							460
Rate-regulated electric revenues		2,333	1,259	1,254			(2)	4,844
Rate-regulated natural gas revenues			387	410			(9)	788
Shared service and other revenues						657	(658)	(1)
<b>Intersegment revenues<sup>(e)</sup>:</b>								
2016	\$ 621	\$ 8	\$ 4	\$ 9	\$ 23	\$ 803	\$ (1,466)	\$ 2
2015	360	2	1	8		656	(1,026)	1
<b>Net income (loss):</b>								
2016	\$ 285	\$ 260	\$ 224	\$ 135	\$ (257)	\$ (215)	\$ (2)	\$ 430
2015	875	189	209	157		(55)	(3)	1,372

- (a) Generation includes the six power marketing 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, 2016 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 six months ended June 30, 2015, intersegment revenues for Generation include revenue from sales to PECO of \$112 million and sales to BGE of \$235 million in the Mid-Atlantic region, and sales to ComEd of \$15 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 the PHI's successor period, March 24, 2016 through June 30, 2016. PHI includes the three reportable segments: Pepco, DPL and ACE. See tables below for PHI's predecessor periods, including Pepco, DPL and ACE, for January 1, 2016 to March 23, 2016 and for the six months ended June 30, 2015.
- (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 19 - Supplemental Financial Information for total utility taxes for the three months ended June 30, 2016 and 2015.



**Table of Contents****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.

**Generation total revenues:**

	Six Months Ended June 30, 2016			Six Months Ended June 30, 2015		
	Revenues from external customers <sup>(a)</sup>	Intersegment revenues	Total Revenues	Revenues from external customers <sup>(a)(c)</sup>	Intersegment revenues <sup>(c)</sup>	Total Revenues <sup>(c)</sup>
Mid-Atlantic	\$ 2,964	\$ (28)	\$ 2,936	\$ 2,920	\$ (61)	\$ 2,859
Midwest	2,166	13	2,179	2,482		2,482
New England	823	(2)	821	1,232	(6)	1,226
New York	573	(24)	549	529	(1)	528
ERCOT	370		370	375	(3)	372
Other Power Regions	456	(9)	447	522	(19)	503
<b>Total Revenues for Reportable Segments</b>	<b>7,352</b>	<b>(50)</b>	<b>7,302</b>	<b>8,060</b>	<b>(90)</b>	<b>7,970</b>
Other <sup>(b)</sup>	977	50	1,027	2,014	90	2,104
<b>Total Generation Consolidated Operating Revenues</b>	<b>\$ 8,329</b>	<b>\$</b>	<b>\$ 8,329</b>	<b>\$ 10,074</b>	<b>\$</b>	<b>\$ 10,074</b>

(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. Also includes an \$11 million and a \$22 million increase to revenues for the amortization of intangible assets related to commodity contracts recorded at fair value for the six months ended June 30, 2016 and 2015, respectively, unrealized mark-to-market losses of \$553 million and gains of \$179 million for the six months ended June 30, 2016 and 2015, respectively, and elimination of intersegment revenues.

(c) Exelon corrected an error in the June 30, 2015 balances within Intersegment Revenue and Revenue from external customers for an overstatement of \$89 million of Intersegment Revenue for Reportable Segments for the six months ended June 30, 2015, an understatement of Revenue from external customers for Reportable Segments of \$89 million for the six months ended June 30, 2015, an understatement of \$89 million of Intersegment Revenue for Other for the six months ended June 30, 2015, and an overstatement of Revenue from external customers for Other of \$89 million for the six months ended June 30, 2015. This error is not considered material to any prior period, and there is no impact to Total Revenues.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**Generation total revenues net of purchased power and fuel expense:**

	Six Months Ended June 30, 2016			Six Months Ended June 30, 2015		
	RNF from external customers <sup>(a)</sup>	Intersegment RNF	Total RNF	RNF from external customers <sup>(a)(c)</sup>	Intersegment RNF <sup>(c)</sup>	Total RNF <sup>(c)</sup>
Mid-Atlantic	\$ 1,661	\$ 8	\$ 1,669	\$ 1,690	\$ (11)	\$ 1,679
Midwest	1,443	6	1,449	1,454	(6)	1,448
New England	204	(13)	191	277	(31)	246
New York	408	(13)	395	306	28	334
ERCOT	192	(54)	138	179	(54)	125
Other Power Regions	211	(37)	174	185	(77)	108
<b>Total Revenues net of purchased power and fuel expense for Reportable Segments</b>	<b>4,119</b>	<b>(103)</b>	<b>4,016</b>	<b>4,091</b>	<b>(151)</b>	<b>3,940</b>
Other <sup>(b)</sup>	190	103	293	701	151	852
<b>Total Generation Revenues net of purchased power and fuel expense</b>	<b>\$ 4,309</b>	<b>\$</b>	<b>\$ 4,309</b>	<b>\$ 4,792</b>	<b>\$</b>	<b>\$ 4,792</b>

(a) Includes purchases and sales from 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. Also includes a \$7 million and a \$24 million increase to RNF for the amortization of intangible assets related to commodity contracts for the six months ended June 30, 2016 and 2015, respectively, unrealized mark-to-market losses of \$201 million and gains of \$397 million for the six months ended June 30, 2016 and 2015, respectively, accelerated nuclear fuel amortization associated with nuclear decommissioning as discussed at Note 7 Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements of \$9 million for the six months ended June 30, 2016, and the elimination of intersegment revenue net of purchased power and fuel expense.

(c) Exelon corrected an error in the June 30, 2015 balances within Intersegment RNF and RNF from external customers for an understatement of \$25 million of Intersegment RNF for Reportable Segments for the six months ended June 30, 2015, an overstatement of RNF from external customers for Reportable Segments of \$10 million for the six months ended June 30, 2015, an overstatement of \$25 million of Intersegment RNF for Other for the six months ended June 30, 2015, and an understatement of RNF from external customers for Other of \$10 million for the six months ended June 30, 2015. This also included an understatement of total RNF for Reportable Segments and an overstatement of total RNF for Other of \$15 million for the six months ended June 30, 2015. The error is not considered material to any prior period, and there is no net impact to Generation Total RNF for 2015.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**Successor and Predecessor PHI:**

	Pepco	DPL	ACE	Other <sup>(b)</sup>	Intersegment Eliminations	PHI
<b>Operating revenues<sup>(a)</sup>:</b>						
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						
Six months ended June 30, 2015	Predecessor					
Rate-regulated electric revenues	\$ 1,049	\$ 580	\$ 618	\$ 115	\$	\$ 2,362
Rate-regulated natural gas revenues		111				111
Shared service and other revenues						
<b>Intersegment revenues:</b>						
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)	
Six months ended June 30, 2015	Predecessor					
	2	3	2		(7)	
<b>Net income (loss):</b>						
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
Six months ended June 30, 2015	Predecessor					
	68	40	15	(17)		106

(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 19 - Supplemental Financial Information for total utility taxes for the six months ended June 30, 2016 and 2015.

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

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

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

**Exelon Corporation**

**General**

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.

Exelon has twelve reportable segments consisting of Generation's six power marketing 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 20 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.

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.

**Table of Contents****Executive Overview****Financial Results**

The following tables set forth the consolidated financial results of Exelon for the three and six months ended June 30, 2016 compared to the same periods in 2015. The 2016 financial results only 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, 2016							2015	Favorable (Unfavorable) Variance
	Generation	ComEd	PECO	BGE	PHI <sup>(b)</sup>	Other	Exelon		
<b>Operating revenues</b>	\$ 3,589	\$ 1,286	\$ 664	\$ 680	\$ 1,066	\$ (375)	\$ 6,910	\$ 6,514	\$ 396
<b>Purchased power and fuel</b>	1,577	339	217	261	416	(356)	2,454	2,449	(5)
<b>Revenue net of purchased power and fuel<sup>(a)</sup></b>	2,012	947	447	419	650	(19)	4,456	4,065	391
<b>Other operating expenses</b>									
Operating and maintenance	1,530	368	190	208	246	(37)	2,505	2,042	(463)
Depreciation and amortization	408	190	67	97	160	19	941	602	(339)
Taxes other than income	118	65	38	55	108	10	394	294	(100)
Total other operating expenses	2,056	623	295	360	514	(8)	3,840	2,938	(902)
<b>Gain on sales of assets</b>	31						31	7	24
<b>Operating (loss) income</b>	(13)	324	152	59	136	(11)	647	1,134	(487)
<b>Other income and (deductions)</b>									
Interest expense, net	(99)	(91)	(31)	(24)	(66)	(65)	(376)	(155)	(221)
Other, net	117	3	2	5	11	6	144	(17)	161
Total other income and (deductions)	18	(88)	(29)	(19)	(55)	(59)	(232)	(172)	(60)
<b>Income (loss) before income taxes</b>	5	236	123	40	81	(70)	415	962	(547)
<b>Income taxes</b>	(31)	91	23	6	29	(16)	102	327	225
<b>Equity in (losses) earnings of unconsolidated affiliates</b>	(8)					1	(7)	(2)	(5)
<b>Net income (loss)</b>	28	145	100	34	52	(53)	306	633	(327)
Net income (loss) attributable to noncontrolling interests and preference stock dividends	36			3			39	(5)	(44)
<b>Net (loss) income attributable to common shareholders</b>	\$ (8)	\$ 145	\$ 100	\$ 31	\$ 52	\$ (53)	\$ 267	\$ 638	\$ (371)

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

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report.

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

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	Six Months Ended June 30, 2016							2015	Favorable (Unfavorable)
	Generation	ComEd	PECO	BGE	PHI <sup>(b)</sup>	Other	Exelon	Exelon	Variance
<b>Operating revenues</b>	\$ 8,329	\$ 2,535	\$ 1,505	\$ 1,609	\$ 1,171	\$ (664)	\$ 14,485	\$ 15,345	\$ (860)
<b>Purchased power and fuel</b>	4,020	686	537	634	454	(623)	5,708	6,919	1,211
<b>Revenue net of purchased power and fuel<sup>(a)</sup></b>	4,309	1,849	968	975	717	(41)	8,777	8,426	351
<b>Other operating expenses</b>									
Operating and maintenance	2,997	736	405	410	695	98	5,341	4,123	(1,218)
Depreciation and amortization	697	379	134	206	174	36	1,626	1,212	(414)
Taxes other than income	244	141	80	114	123	18	720	598	(122)
Total other operating expenses	3,938	1,256	619	730	992	152	7,687	5,933	(1,754)
<b>Gain on sales of assets</b>	31	5				4	40	8	32
<b>Operating income (loss)</b>	402	598	349	245	(275)	(189)	1,130	2,501	(1,371)
<b>Other income and (deductions)</b>									
Interest expense, net	(196)	(177)	(62)	(48)	(71)	(109)	(663)	(501)	(162)
Other, net	210	7	4	11	12	14	258	64	194
Total other income and (deductions)	14	(170)	(58)	(37)	(59)	(95)	(405)	(437)	32
<b>Income (loss) before income taxes</b>	416	428	291	208	(334)	(284)	725	2,064	(1,339)
<b>Income taxes</b>	120	168	67	73	(77)	(66)	285	690	405
<b>Equity in (losses) earnings of unconsolidated affiliates</b>	(11)					1	(10)	(2)	(8)
<b>Net income (loss)</b>	285	260	224	135	(257)	(217)	430	1,372	(942)
Net (loss) income attributable to noncontrolling interests and preference stock dividends	(17)			6		1	(10)	41	51
<b>Net income (loss) attributable to common shareholders</b>	\$ 302	\$ 260	\$ 224	\$ 129	\$ (257)	\$ (218)	\$ 440	\$ 1,331	\$ (891)

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

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

*Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015.* Exelon's net income attributable to common shareholders was \$267 million for the three months ended June 30, 2016 as compared to \$638 million for the three months ended June 30, 2015, and diluted earnings per average common share were \$0.29 for the three months ended June 30, 2016 as compared to \$0.74 for the three months ended June 30, 2015.



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Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by \$391 million for the three months ended June 30, 2016 as compared to the same period in 2015. The quarter-over-quarter increase in operating revenue net of purchased power and fuel expense was primarily due to the following favorable factors:

Increase of \$104 million at Generation primarily due to the approval of the Ginna Reliability Support Services Agreement, decreased nuclear fuel prices and increased capacity prices, partially offset by lower realized energy prices and the impact of increased nuclear outage days;

Increase of \$74 million at ComEd primarily due to increased distribution and transmission formula rate revenue resulting from favorable weather and increased capital investment, partially offset by lower allowed electric distribution ROE due to a decrease in treasury rates;

Increase of \$30 million at BGE primarily due to increased transmission revenue as a result of increased capital investments and operating and maintenance expense recoveries and increased distribution revenue pursuant to increased rates effective in June 2016;

Increase of \$23 million at PECO primarily due to increased electric distribution revenue pursuant to a rate increase effective January 1, 2016; and

Increase of \$650 million in revenue net of purchased power and fuel due to the inclusion of PHI's results for the period of April 1, 2016 to June 30, 2016.

The quarter-over-quarter increase in operating revenue net of purchased power and fuel expense was partially offset by a decrease of \$539 million at Generation due to mark-to-market losses of \$304 million in 2016 from economic hedging activities as compared to gains of \$235 million in 2015.

Operating and maintenance expense increased by \$463 million for the three months ended June 30, 2016 as compared to the same period in 2015 primarily due to the following unfavorable factors:

Increase of \$141 million at Generation for the recognition of one-time charges associated with Generation's decision to early retire Clinton and Quad Cities nuclear generating facilities during the second quarter of 2016;

Increase of \$52 million at BGE as a result of one-time charges associated with the reduction of certain regulatory assets and other long-lived assets stemming from certain cost disallowances contained within the smart grid rate case orders issued by the MDPSC in June and July 2016;

Long-lived asset impairments of certain wind projects at Generation of \$36 million;

Increase in Generation's labor, contracting and materials cost of \$31 million primarily due to timing and extended duration of an outage at the Salem nuclear power plant and the inclusion of Pepco Energy Services results in 2016; and

Increase of \$246 million in operating and maintenance expense due to the inclusion of PHI's results for the period of April 1, 2016 to June 30, 2016.

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The quarter-over-quarter increase in operating and maintenance expense was partially offset by the following favorable factors:

Decrease of \$17 million at PECO due to lower incremental storm costs in the second quarter of 2016 compared to the second quarter of 2015, as a result of the June 2015 storm; and

Decrease of \$22 million in pension and non-pension post-retirement benefits resulting from the favorable impact of higher pension and OPEB discount rates in 2016.

Depreciation and amortization expense increased by \$339 million primarily as a result of accelerated depreciation and amortization expense related to the announcement of the early plant retirements at Generation,

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increased nuclear decommissioning amortization at Generation, increased depreciation expense due to ongoing capital expenditures across all operating companies, and the inclusion of PHI s results for the period of April 1, 2016 to June 30, 2016.

Taxes other than income increased by \$100 million primarily due to increased property and utility taxes as a result of the inclusion of PHI s results for the period of April 1, 2016 to June 30, 2016.

Gain on sales of assets increased by \$24 million primarily as a result of the gain associated with Generation s sale of the retired New Boston generating site.

Interest expense, net increased by \$221 million primarily as a result of the inclusion of PHI s results for the period of April 1, 2016 to June 30, 2016 and higher outstanding debt to fund the PHI acquisition and general corporate purposes.

Other, net increased by \$161 million primarily at Generation as a result of the change in realized and unrealized gains and losses on NDT funds.

Exelon s effective income tax rates for the three months ended June 30, 2016 and 2015 were 24.6% and 34.0%, 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.

*Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015.* Exelon s net income attributable to common shareholders was \$440 million for the six months ended June 30, 2016 as compared to \$1,331 million for the six months ended June 30, 2015, and diluted earnings per average common share were \$0.48 for the six months ended June 30, 2016 as compared to \$1.54 for the six months ended June 30, 2015.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by \$351 million for the six months ended June 30, 2016 as compared to the same period in 2015. The year-over-year increase in operating revenue net of purchased power and fuel expense was primarily due to the following favorable factors:

Increase of \$117 million at ComEd primarily due to increased distribution and transmission formula rate revenue resulting from increased capital investment;

Increase of \$76 million at Generation primarily due to approval of the Ginna Reliability Support Services Agreement, decreased nuclear fuel prices, increased capacity prices, and decreased nuclear outage days at higher capacity units, partially offset by lower realized energy prices and higher oil inventory write downs.

Increase of \$37 million at BGE primarily due to increased transmission revenue as a result of increased capital investments and operating and maintenance expense recoveries and increased distribution revenue pursuant to increased rates effective in June 2016; and

Increase of \$717 million in revenue net of purchased power and fuel due to the inclusion of PHI s results for the period of March 24, 2016 to June 30, 2016.

The year-over-year increase in operating revenue net of purchased power and fuel expense was partially offset by a decrease of \$598 million at Generation due to mark-to-market losses of \$201 million in 2016 from economic hedging activities as compared to gains of \$397 million in 2015.

Operating and maintenance expense increased by \$1,218 million for the six months ended June 30, 2016 as compared to the same period in 2015 primarily due to the following unfavorable factors:

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Approval of the merger across all regulatory jurisdictions was conditioned on Exelon and PHI agreeing to certain commitments pursuant to which, upon acquisition close, Exelon recorded \$508 million of costs.

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Long-lived asset impairments of Upstream assets and certain wind projects at Generation of \$155 million;

Increase of \$141 million at Generation for the recognition of one-time charges associated with Generation's decision to early retire the Clinton and Quad Cities nuclear generating facilities during the second quarter of 2016;

Increase of \$52 million at BGE as a result of one-time charges associated with the reduction of certain regulatory assets and other long-lived assets stemming from certain cost disallowances contained within the smart grid rate case orders issued by the MDPSC in June and July 2016;

Increased storm costs at BGE of \$18 million; and

Increase of \$332 million, net of merger commitment costs discussed above, due to the inclusion of PHI's results for 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 \$38 million in uncollectible accounts at ComEd, PECO and BGE;

Decrease of \$40 million in pension and non-pension post-retirement benefits resulting from the favorable impact of higher pension and OPEB discount rates in 2016; and

Decrease of \$14 million at PECO due to lower incremental storm costs in the second quarter of 2016 compared to the second quarter of 2015, as a result of the June 2015 storm.

Depreciation and amortization expense increased by \$414 million primarily as a result of accelerated depreciation and amortization expense related to the announcement of the early plant retirements at Generation, increased nuclear decommissioning amortization at Generation, increased depreciation expense due to ongoing capital expenditures across all operating companies, and the inclusion of PHI's results for the period of March 24, 2016 to June 30, 2016.

Taxes other than income increased by \$122 million primarily due to increased property and utility taxes as a result of the inclusion of PHI's results for the period March 24, 2016 to June 30, 2016.

Gain on sales of assets increased by \$32 million primarily as a result of the gain associated with Generation's sale of the retired New Boston generating site.

Interest expense, net increased by \$162 million primarily as a result of higher outstanding debt to fund the PHI acquisition and general corporate purposes and the absence of the forward-starting interest rate swaps in 2016.

Other, net increased by \$194 million primarily at Generation as a result of the change in realized and unrealized gains and losses on NDT funds and the absence of a \$26 million loss in 2015 on the termination of forward-starting interest rate swaps.

Exelon's effective income tax rates for the six months ended June 30, 2016 and 2015 were 39.3% and 33.4%, 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. As a result of the merger, Exelon recorded an after-tax charge of \$90 million during the six months ended June 30, 2016 as a result of the assessment and remeasurement of certain federal and state PHI, Pepco, DPL and ACE uncertain tax positions.

For further detail regarding the financial results for the three and six months ended June 30, 2016, 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.



**Table of Contents****Non-GAAP Financial Measures**

Exelon's adjusted (non-GAAP) operating earnings for the three months ended June 30, 2016 were \$604 million, or \$0.65 per diluted share, compared with adjusted (non-GAAP) operating earnings of \$508 million, or \$0.59 per diluted share for the same period in 2015. Exelon's adjusted (non-GAAP) operating earnings for the six months ended June 30, 2016 were \$1,235 million, or \$1.33 per diluted share, compared with adjusted (non-GAAP) operating earnings of \$1,123 million, or \$1.30 per diluted share for the same period in 2015. In addition to net income as determined under generally accepted accounting principles in the United States (GAAP), Exelon evaluates its operating performance using 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' presentation. The Company has provided non-GAAP financial measures as supplemental information and in addition to the financial measures that are calculated and presented in accordance with GAAP. Non-GAAP financial measures should not be deemed more useful than, a substitute for, or an alternative to the most comparable GAAP measures 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, 2016 as compared to the same periods in 2015. The footnotes below the table provide tax expense (benefit) impacts:

	Three Months Ended June 30,			
	2016		2015	
		Earnings per Diluted Share		Earnings per Diluted Share
<i>(All amounts after tax)</i>				
<b>Net Income Attributable to Common Shareholders</b>	\$ 267	\$ 0.29	\$ 638	\$ 0.74
Mark-to-Market Impact of Economic Hedging Activities <sup>(a)</sup>	185	0.20	(143)	(0.16)
Unrealized (Gains) Losses Related to NDT Fund Investments <sup>(b)</sup>	(27)	(0.03)	56	0.06
Merger and Integration Costs <sup>(c)</sup>	1		18	0.02
Merger Commitments <sup>(d)</sup>	1			
Mark-to-Market Impact of PHI Merger Related Interest Rate Swaps <sup>(e)</sup>			(71)	(0.08)
Long-Lived Asset Impairments <sup>(f)</sup>	22	0.02	15	0.02
Amortization of Commodity Contract Intangibles <sup>(g)</sup>	8	0.01	9	0.01
Plant Retirements and Divestitures <sup>(h)</sup>	133	0.14		
Cost Management Program <sup>(i)</sup>	6	0.01		
CENG Non-Controlling Interests <sup>(k)</sup>	8	0.01	(14)	(0.02)
<b>Adjusted (non-GAAP) Operating Earnings</b>	\$ 604	\$ 0.65	\$ 508	\$ 0.59

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	Six Months Ended June 30,			
	2016		2015	
	Earnings per Diluted Share		Earnings per Diluted Share	
<b>(All amounts after tax)</b>				
<b>Net Income Attributable to Common Shareholders</b>	\$ 440	\$ 0.48	\$ 1,331	\$ 1.54
Mark-to-Market Impact of Economic Hedging Activities <sup>(a)</sup>	121	0.12	(243)	(0.27)
Unrealized (Gains) Losses Related to NDT Fund Investments <sup>(b)</sup>	(59)	(0.07)	32	0.04
Merger and Integration Costs <sup>(c)</sup>	79	0.09	37	0.04
Merger Commitments <sup>(d)</sup>	395	0.43		
Mark-to-Market Impact of PHI Merger Related Interest Rate Swaps <sup>(e)</sup>			(21)	(0.03)
Long-Lived Asset Impairments <sup>(f)</sup>	93	0.10	15	0.02
Amortization of Commodity Contract Intangibles <sup>(g)</sup>	(4)		(15)	(0.02)
Plant Retirements and Divestitures <sup>(h)</sup>	133	0.14		
Cost Management Program <sup>(i)</sup>	19	0.02		
Midwest Generation Bankruptcy Recoveries <sup>(i)</sup>			(6)	(0.01)
CENG Non-Controlling Interests <sup>(k)</sup>	18	0.02	(7)	(0.01)
<b>Adjusted (non-GAAP) Operating Earnings</b>	<b>\$ 1,235</b>	<b>\$ 1.33</b>	<b>\$ 1,123</b>	<b>\$ 1.30</b>

- (a) Reflects the impact of net (gains) losses for the three months ended June 30, 2016 and 2015 (net of taxes \$120 million and \$92 million, respectively) and the six months ended June 30, 2016 and 2015 (net of taxes of \$81 million and \$155 million, respectively), 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) losses for the three months ended June 30, 2016 and 2015 (net of taxes \$29 million and \$71 million, respectively) and the for the six months ended June 30, 2016 and 2015 (net of taxes of \$64 million and \$44 million, respectively), 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 certain costs incurred for the three months ended June 30, 2015 (net of taxes \$10 million) and the six months ended June 30, 2016 and 2015 (net of taxes of \$26 million and \$24 million, respectively), including professional fees, employee-related expenses, integration activities, upfront credit facilities fees, and the PHI acquisition. See Note 4 Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional detail related to merger and acquisition costs.
- (d) Reflects the costs incurred as part of the settlement orders approving the PHI acquisition for the six months ended June 30, 2016 (net of taxes of \$113 million). See Note 4 Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional detail related to PHI Merger commitments.
- (e) Reflects the impact of net losses on forward-starting interest rate swaps at Exelon Corporate related to financing of the PHI acquisition for the three and six months ended June 30, 2015 (net of taxes of \$45 million and \$14 million, respectively).
- (f) Reflects the impairment of Upstream assets and certain wind projects at Generation for the three and six months ended June 30, 2016 (net of taxes of \$14 million and \$62 million, respectively). Reflects the impairment of investment in long-term leases at Corporate for the three and six months ended June 30, 2015 (net of taxes of \$9 million).
- (g) Reflects the non-cash impact for the three months ended June 30, 2016 and 2015 (net of taxes \$4 million and \$5 million, respectively) and the for the six months ended June 30, 2016 and 2015 (net of taxes of \$2 million and \$9 million, respectively), of the amortization of intangible assets, net, related to commodity contracts recorded at fair value for the Integrys acquisition.
- (h) Reflects the accelerated depreciation and amortization expense, increases to materials and supplies inventory reserves, severance benefits and construction work in progress impairment charges associated with the announcement of the early retirement of Generation's Clinton and Quad Cities nuclear facilities, partially offset by a gain associated with Generation's sale of the retired New Boston generating site for the three and six months ended June 30, 2016 (net of taxes \$85 million).
- (i) Reflects the 2016 severance expense and reorganization costs related to a cost management program for the three and six months ended June 30, 2016 (net of taxes of \$3 million and \$12 million, respectively).



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- (j) For the six months ended June 30, 2015, reflects a benefit related to the favorable settlement of a long term railcar lease agreement pursuant to the Midwest Generation bankruptcy (net of taxes of \$4 million).
- (k) Represents Generation's noncontrolling interests related to CENG exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments.

**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.

The table below presents the one-time pre-tax charges recognized upon closing of the PHI Merger included in the Registrant's respective Consolidated Statements of Operations and Comprehensive Income.

	Six Months Ended June 30, 2016					Successor
	Exelon	Generation	Pepco	DPL	ACE	March 24, 2016 to June 30, 2016 PHI
Merger commitments	\$ 508	\$ 3	\$ 139	\$ 104	\$ 120	\$ 363
Changes in accounting and tax related policies and estimates			25	15	5	
<b>Total</b>	<b>\$ 508</b>	<b>\$ 3</b>	<b>\$ 164</b>	<b>\$ 119</b>	<b>\$ 125</b>	<b>\$ 363</b>

In addition to the one-time PHI Merger charges discussed above, for the three and six months ended June 30, 2016, expense has been recognized for merger, integration and acquisition costs for the PHI Merger and for the three and six months ended June 30, 2015, expense has been recognized primarily for merger, integration and acquisition costs for the PHI Merger and Integrys acquisition as follows:

Merger, Integration and Acquisition Costs:	Pre-tax Expense								
	Three Months Ended June 30, 2016								
	Exelon <sup>(a)</sup>	Generation <sup>(a)</sup>	ComEd	PECO	BGE	PHI <sup>(a)</sup>	Pepco <sup>(a)</sup>	DPL <sup>(a)</sup>	ACE <sup>(a)</sup>
Employee-Related <sup>(d)</sup>	\$ 2	\$ (1)	\$ (1)	\$	\$	\$ 4	\$ 2	\$ 1	\$ 1
Other <sup>(f)</sup>	(1)	5	2	1	(5)	(5)	(6)	(1)	1
<b>Total</b>	<b>\$ 1</b>	<b>\$ 4</b>	<b>\$ 1</b>	<b>\$ 1</b>	<b>\$ (5)</b>	<b>\$ (1)</b>	<b>\$ (4)</b>	<b>\$</b>	<b>\$ 2</b>

Merger, Integration and Acquisition Costs:	Pre-tax Expense				
	Three Months Ended June 30, 2015				
	Exelon	Generation	ComEd	PECO	BGE
Financing <sup>(b)</sup>	\$ (104)	\$	\$	\$	\$
Transaction <sup>(c)</sup>	3				
Employee-Related <sup>(d)</sup>	(1)	(1)			
Other	15	8	3	1	1
<b>Total</b>	<b>\$ (87)</b>	<b>\$ 7</b>	<b>\$ 3</b>	<b>\$ 1</b>	<b>\$ 1</b>



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Merger, Integration and Acquisition Costs:	Pre-tax Expense								
	Six Months Ended June 30, 2016								
	Exelon <sup>(a)</sup>	Generation <sup>(a)</sup>	ComEd	PECO	BGE	PHI <sup>(a)</sup>	Pepco <sup>(a)</sup>	DPL <sup>(a)</sup>	ACE <sup>(a)</sup>
Transaction <sup>(c)</sup>	\$ 35	\$	\$	\$	\$	\$	\$	\$	\$
Employee-Related <sup>(d)</sup>	73	10	1	1	1	60	29	17	14
Other <sup>(e)(f)</sup>	(5)	10	(8)	1	(5)	(5)	(6)	(1)	1
Total	\$ 103	\$ 20	\$ (7)	\$ 2	\$ (4)	\$ 55	\$ 23	\$ 16	\$ 15

Merger and Integration Costs:	Pre-tax Expense				
	Six Months Ended June 30, 2015				
	Exelon	Generation	ComEd	PECO	BGE
Financing <sup>(b)</sup>	\$ (15)	\$	\$	\$	\$
Transaction <sup>(c)</sup>	9				
Employee-Related <sup>(d)</sup>	3	3			
Other	28	16	6	2	3
Total	\$ 25	\$ 19	\$ 6	\$ 2	\$ 3

(a) For Exelon, Generation, PHI, Pepco, DPL, and ACE, includes the operations of the acquired businesses beginning on March 24, 2016.

(b) Reflects costs incurred at Exelon related to the financing of the PHI Merger, including upfront credit facility fees and mark-to-market activity on forward-starting interest rate swaps.

(c) External, third party costs paid to advisors, consultants, lawyers and other experts to assist in the due diligence and regulatory approval processes and in the closing of transactions.

(d) Costs primarily for employee severance, pension and OPEB expense and retention bonuses.

(e) 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.

(f) For the three and six months ended June 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of \$6 million, \$9 million, \$3 million and \$12 million incurred at BGE, Pepco, DPL and PHI, respectively, 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.

As of June 30, 2016, Exelon expects to incur total PHI acquisition and integration related costs of approximately \$700 million, excluding merger commitments. Of this amount, including 2014 and through June 30, 2016, Exelon and PHI have incurred approximately \$520 million. Included in this amount are costs to fund the merger of which \$76 million has been expensed, \$56 million has been paid and recorded as deferred debt issuance costs and \$60 million has been incurred and charged to common stock. The remaining costs will be primarily within Operating and maintenance expense within Exelon's Consolidated Statements of Operations and Comprehensive Income and will also include approximately \$60 million for integration costs expected to be capitalized to Property, plant and equipment. See Note 4 Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for further information regarding the PHI acquisition.

**Exelon's Strategy and Outlook for the remainder of 2016 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 stable earnings, which translates to a stable currency in our stock.

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Generation s competitive businesses provide free cash flow to invest primarily into the utilities and in long-term, contracted assets.

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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 prudently and 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 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 solutions and reliable, clean and affordable energy. Generation's electricity generation strategy is to pursue opportunities that provide 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.

Several nuclear units within the Exelon fleet and nationally are economically challenged, threatened by persistently low prices and out-of-market payments to select generation sources. Some units have already retired prematurely for economic reasons, and Exelon has announced the planned early shutdown of its Clinton and Quad Cities units. Other Exelon units face similar challenges, most notably Ginna, Nine Mile Point and TMI. Exelon is working to develop possible solutions at the state, federal and RTO levels so that markets or the states more appropriately value the carbon-free emission attribute of nuclear generation.

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 approved a revised dividend policy. The approved policy raises our dividend 2.5% each year for the next three years, beginning with the June 2016 dividend.

Various market, financial, and other factors could affect the Registrants' success in pursuing their strategies. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these issues. See ITEM 1A. RISK FACTORS of the Exelon 2015 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. Through a recent focused cost management program, the company has committed to reducing operation and maintenance expenses and capital costs by \$350 million, of which approximately 35% of run-rate savings are expected to be achieved by the end of 2016 and fully realized in 2018. At least 75% of the savings are expected to be allocated to Generation, with the remaining amount allocated to the Utility Registrants. Exelon anticipates the earnings per share savings impact on EPS will be within \$0.13 to \$0.18 from 2018 forward.

***Early Nuclear Plant Retirements***

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

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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 final rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules.

In 2015, Generation identified the Quad Cities, Clinton and Ginna nuclear plants as having the greatest risk of early retirement based on economic valuation and other factors. At that time, Exelon and Generation deferred retirement decisions on Clinton and Quad Cities until 2016 in order to participate in the 2016-2017 MISO primary reliability auction and the 2019-2020 PJM capacity auctions held in April and May 2016, respectively, as well as to provide Illinois policy makers with additional time to consider needed reforms and for MISO to consider market design changes to ensure long-term power system reliability in southern Illinois.

In April 2016, Clinton cleared the MISO primary reliability auction as a price taker for the 2016-2017 planning year. The resulting capacity price is insufficient to cover cash operating costs and a risk-adjusted rate of return to shareholders. In May 2016, Quad Cities did not clear in the PJM capacity auction for the 2019-2020 planning year and will not receive capacity revenue for that period.

Based on these capacity auction results, and given the lack of progress on Illinois energy legislation and MISO market reforms, on June 2, 2016 Generation announced it will move forward to shut down the Clinton and Quad Cities nuclear plants on June 1, 2017 and June 1, 2018, respectively. The current Nuclear Regulatory Commission (NRC) licenses for Clinton and Quad Cities expire in 2026 and 2032, respectively. Generation is proceeding with the market and regulatory notifications that must be made to shut down the plants, including notification to the NRC on June 20, 2016, and filing of a deactivation notice with PJM for Quad Cities on July 6, 2016. Generation will formally notify MISO of its plans to close Clinton later this year.

In second quarter of 2016, as a result of the plant retirement decision for Clinton and Quad Cities, Exelon and Generation recognized one-time charges in Operating and maintenance expense of \$141 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 Clinton and Quad Cities 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 2016 results include an incremental \$110 million of pre-tax expense for these items. The following table summarizes the estimated annual amount and timing of such expected incremental non-cash expense items through 2018.

Income statement expense (pre-tax)	June 30, 2016	2016	Projected <sup>(a)</sup> 2017	2018
Depreciation and Amortization				
Accelerated depreciation <sup>(b)</sup>	\$ 115	\$ 800	\$ 860	\$ 200
Accelerated nuclear fuel amortization	9	70	75	20
Operating and Maintenance				
Increase ARO accretion, net of contractual offset <sup>(c)</sup>		5	5	5
Contractual offset for ARC depreciation <sup>(c)</sup>	(14)	(100)	(160)	(60)
<b>Total</b>	<b>\$ 110</b>	<b>\$ 775</b>	<b>\$ 780</b>	<b>\$ 165</b>

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

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

(c) 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

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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.

Please refer to Note 12 Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional detail on changes to the Nuclear decommissioning ARO balances resulting from the early retirement of Clinton and Quad Cities.

The Three Mile Island (TMI) nuclear plant also did not clear in the May 2016 PJM capacity auction for the 2019-2020 planning year and will not receive capacity revenue for that period. This is the second consecutive year that TMI failed to clear the capacity auction. Although the plant is committed to operate through May 2018, the plant faces continued economic challenges and Exelon and Generation are exploring all options to return it to profitability. While a portion of the Byron nuclear plant's capacity did not clear the PJM 2019-2020 planning year capacity auction, the plant is committed to run through May 2020. The company's other nuclear plants in PJM cleared in the auction, except Oyster Creek, which did not participate in the auction given Exelon's and Generation's previous commitment to cease operation of the Oyster Creek nuclear plant by the end of 2019.

In New York, the Ginna and Nine Mile Point nuclear plants continue to face 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, and 2046 for Nine Mile Point Unit 2). On August 1, 2016, the New York Public Service Commission (NYPSC) issued an order adopting the Clean Energy Standard (CES), which would provide payments to Ginna and Nine Mile Point for the environmental attributes of their production. Subject to Ginna and Nine Mile Point entering into a satisfactory contract with the New York State Energy Research & Development Agency (NYSERDA), as required under the CES, and subject to any potential administrative or legal challenges, the CES will allow Ginna and Nine Mile Point to continue to operate at least through the life of the program (March 31, 2029). The approved RSSA currently requires Ginna to continue operating through the RSSA term expiring in March 2017. If Ginna does not plan to retire shortly after the expiration of the RSSA, Ginna is required to file a notice to that effect with the NYPSC no later than September 30, 2016. Refer to Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional discussion on the Ginna RSSA and the New York CES.

The following table provides the balance sheet amounts as of June 30, 2016 for significant assets and liabilities associated with the three nuclear plants currently considered by management to be at the greatest risk of early retirement due to current economic valuations and other factors.

<i>(in millions)</i>	<b>TMI</b>	<b>Ginna</b>	<b>NMP</b>
<b>Asset Balances</b>			
Materials and supplies inventory	\$ 38	\$ 30	\$ 69
Nuclear fuel inventory, net	104	47	235
Completed plant, net	968	125	1,137
Construction work in progress	35	12	70
<b>Liability Balances</b>			
Asset retirement obligation	(485)	(659)	(770)
NRC License Renewal Term	2034	2029	2029 (unit 1) 2046 (unit 2)

The precise timing of an early retirement date for any of these plants, 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 obligations, where applicable, and just prior to its next scheduled nuclear refueling outage.

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

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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.

It is currently estimated that Clinton 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. Quad Cities is also at risk for such a shortfall. 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 of 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. Considering the three alternative decommissioning approaches available for each site, the most costly estimates currently anticipated could require parental guarantees of up to \$385 million for Clinton in order to access its NDT fund for radiological decommissioning costs. Although Quad Cities is better positioned than Clinton to avoid the need for a parental guarantee, a guarantee of up to \$135 million, at Generation's ownership percentage, may be required in order for the site to access its NDT fund for radiological decommissioning costs. As of June 30, 2016, the additional plants at the highest risk of early retirement, Ginna, Nine Mile Point and TMI, pass the NRC minimum funding test based on their current license lives. However, in the event of an early retirement the most costly estimates currently anticipated could require parental guarantees of up to \$130 million, \$205 million, and \$80 million for Ginna, Nine Mile Point and TMI, respectively, at Generation's ownership percentages.

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). Accordingly, based on current projections, it is expected that some portion of the spent fuel management and/or site restoration costs would need to be funded through supplemental cash from Generation and others holding ownership interests. 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 three alternative decommissioning approaches available, for the next 10 years, Clinton could incur spent fuel management and site restoration costs of up to \$160 million, net of taxes. Quad Cities is better positioned to pass the test than Clinton. Although considered unlikely, if Quad Cities fails the exemption test, at its ownership percentage Generation could be required to pay for spent fuel management costs over the next ten years of up to \$185 million, net of taxes, at Generation's ownership percentage. If an early retirement decision is made and Ginna, Nine Mile Point, or TMI were to fail the exemption test, each could incur spent fuel management and site restoration costs over the next ten years of up to \$60 million, \$140 million and \$145 million, net of taxes, respectively, at Generation's ownership percentages.

**Proposed Acquisition of ConEdison Solutions (Exelon and Generation)**

On July 27, 2016, Generation entered into an Asset Purchase Agreement (the Purchase Agreement) with ConEdison Solutions, a subsidiary of Consolidated Edison, Inc. (collectively ConEdison). Pursuant to the Purchase Agreement, ConEdison Solutions agreed to sell its competitive retail electric and natural gas business to Generation for an all cash purchase price of \$53 million plus estimated purchase price adjustments, including net working capital, of \$130 million. Pursuant to the Purchase Agreement, Generation has agreed to use its commercially reasonable efforts to replace the guarantees and other credit support currently being provided by



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ConEdison in support of the ongoing competitive retail electric and natural gas business and to reimburse ConEdison for any payments arising pursuant to such arrangements continuing for any post-closing period. The renewable energy, sustainable services and energy efficiency businesses of ConEdison are excluded from the transaction.

The transaction is expected to close in the third or fourth quarter of 2016. The closing of the transaction is subject to certain conditions, including, obtaining the termination or expiration of any applicable waiting period required under the HSR Act for the consummation of the transaction. Either party may terminate the Purchase Agreement if the transaction has not been consummated within six months after the date of the Purchase Agreement. The Purchase Agreement also includes various representations, warranties, covenants, indemnifications and other provisions customary for a transaction of this nature. The total costs directly related to the closing of the transaction are not expected to have a material impact on the financial results of Exelon and Generation.

The transaction is expected to be accounted for as a business combination. Therefore, Generation will record the fair value of the assets acquired and liabilities assumed as of the acquisition date. To the extent the purchase price is greater than the fair value of the net assets acquired, goodwill will be recorded. To the extent the fair value of the net assets acquired is greater than the purchase price, a bargain purchase gain will be recorded.

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

On August 8, 2016, Generation executed a series of agreements with Entergy Nuclear FitzPatrick LLC (Entergy) to acquire the 838MW single-unit James A. FitzPatrick (FitzPatrick) nuclear generating station located in Scriba, New York for a cash purchase price of \$110 million. As part of the transaction, Generation would receive the FitzPatrick NDT fund assets and assume the obligation to decommission FitzPatrick. Closing of the transaction is currently anticipated to occur in the second quarter of 2017 and is dependent upon regulatory approval by FERC, NRC and the New York Public Service Commission (NYPSC). The transaction is also subject to the notification and reporting requirements of the HSR Act and other customary closing conditions. The NRC license for FitzPatrick expires in 2034. Entergy had previously announced plans in November 2015 to early retire FitzPatrick at the end of the current fuel cycle in January 2017. Under the terms of the agreements, Generation will reimburse Entergy for approximately \$200 million to \$250 million of incremental costs to refuel the plant and operate and maintain the plant after the refueling outage, scheduled to end in February 2017, through the closing date. These are costs which otherwise would have been avoided by FitzPatrick's planned permanent shutdown in January 2017, a portion of which for financial reporting purposes will be evaluated as part of the purchase price consideration. Generation will be entitled to all revenues from FitzPatrick's electricity and capacity sales for the period commencing upon completion of the refueling outage through the acquisition closing date. The agreements provide for certain termination rights, including the right of either party to terminate if the transaction has not been consummated within 12 months due to failure to obtain the required regulatory approvals.

The transaction is expected to be accounted for as a business combination. Therefore, Generation will record the fair value of the assets acquired and liabilities assumed as of the acquisition date. To the extent the purchase price is greater than the fair value of the net assets acquired, goodwill will be recorded. To the extent the fair value of the net assets acquired is greater than the purchase price, a bargain purchase gain will be recorded.

***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).

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**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). In June 2016, several parties appealed the FERC's decision approving PJM's market changes to the Court of Appeals for the D. C. Circuit.

**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 alleged 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, the 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, the 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. The FERC ordered that certain rules must be changed for the next auction scheduled in April 2016 that set capacity prices beginning June 1, 2016. In response to this order, MISO filed conforming rule changes with the FERC. The 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. The 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 prejudice the investigation or related proceedings. On March 18, 2016, the FERC denied rehearing of its December 31, 2015 order in this matter. On April 14, 2016, the MISO released the results of the 2016/2017 capacity auction; the zone 4 region in downstate Illinois cleared the auction at a rate of \$72 per MW per day. Clinton nuclear plant, which operates in the zone 4 region, cleared the auction and is committed to operate through May 31, 2017. 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.

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MISO has acknowledged the need for capacity market design changes in the zone 4 region and stated that reforms to its capacity market process may be required to drive future investment and is engaging stakeholders to consider such reforms. The FERC has also encouraged such efforts, and Exelon has been working with MISO and its stakeholders on such market changes.

***Subsidized Generation.*** The rate of expansion of subsidized generation, including low-carbon generation such as wind and solar energy, 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 inappropriately subsidize new generation development and existing generation which may result in artificially depressed wholesale energy and capacity prices.

For example, Exelon and others challenged the constitutionality and other aspects of New Jersey legislation aimed at suppressing capacity market prices in federal court. See Note 5 Regulatory Matters to the Combined Notes to Consolidated Financial Statements for additional information on state specific actions taken in Maryland and New Jersey. Similar 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. Those decisions were upheld by the U.S. Court of Appeals. On April 19, 2016, the U.S. Supreme Court unanimously affirmed the Fourth Circuit decision holding that the MDPSC's required contracts are illegal and unenforceable. On April 25, 2016, the U.S. Supreme Court denied certiorari concerning the Third Circuit decision. This denial of certiorari leaves the Third Circuit decision in place, with the same outcome as the Fourth Circuit decision.

Nonetheless, Exelon believes that these projects may have already artificially suppressed capacity prices in PJM in these auctions. While the Supreme Court decision is a positive development, continuation of inappropriate state efforts, if successful and unabated in future capacity auctions, could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish similar programs, which could substantially impact Exelon's market driven 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 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. Collectively more than 6,000MW of primarily coal-fired generation owned by FE and AEP's affiliates sought ratepayer guaranteed subsidies via the proposed Riders. While AEP and FE initially filed for approval of these Riders in 2013 and 2014, respectively, it was not until late 2015 that the proposals obtained meaningful traction when PUCO staff entered into a settlement and stipulation with the Ohio utilities supporting the proposals and recommending that the PUCO approve the Riders. On March 31, 2016, PUCO issued separate orders generally approving each of the FE and AEP arrangements. In addition, separate complaints were filed at the FERC pursuing federal causes of action (i) seeking to impose affiliate self-dealing requirements on the PPAs and (ii) seeking to impose a MOPR on the resources supporting the PPAs. On April 27, 2016, the FERC issued orders on the affiliate matter rescinding certain affiliate waivers previously granted to AEP and FE and requiring each to demonstrate that the PPAs (prior to transacting under them) were entered into on an arms-length basis and do not reflect any affiliate preference. As a result, we do not believe that the PPAs impacted the results of PJM's recently completed capacity auctions. Nonetheless, further action by AEP and FE related to the PPAs is possible. Indeed, FE recently filed a restructured arrangement at PUCO that appears to achieve a similar result without relying on a PPA. In addition, the outcome of the MOPR complaint and its impact, if any, on Generation is not yet clear as it is too early in the proceeding to predict its outcome. Finally, Dayton Power and Light filed at PUCO seeking approval of similar arrangements.

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Exelon continues to monitor developments in Ohio, Maryland, New Jersey, New England and other states and participates in stakeholder and other processes to ensure that only appropriate state subsidies are 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.

**Energy Demand.** Modest economic growth partially offset by energy efficiency initiatives is resulting in positive growth for electricity for Pepco, a decrease in projected load for electricity for BGE, DPL and ACE, and an essentially flat projected load for electricity for ComEd and PECO. ComEd, PECO, BGE, Pepco, DPL and ACE are projecting load volumes to increase (decrease) by 0.0%, 0.1%, (0.4)%, 1.1%, (1.4)% and (3.7)%, respectively, in 2016 compared to 2015.

**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. 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**

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 the first quarter 2016 dividends of \$0.31 per share each on Exelon's common stock. The first quarter 2016 dividend was paid on March 10, 2016.

Exelon's Board of Directors declared the second quarter 2016 dividends of \$0.318 per share each on Exelon's common stock. The second quarter 2016 dividend was paid on June 10, 2016. The dividend increased from the first quarter 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 third quarter 2016 dividends of \$0.318 per share each on Exelon's common stock. The third quarter 2016 dividend is payable on September 9, 2016.

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 2016 and 2017. 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, 2016, the percentage of expected generation hedged for the major reportable segments is 97%-100%, 78%-81% and 47%-50% for 2016, 2017, and 2018, 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 for capacity based upon a simulated dispatch model that makes assumptions

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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 58% of Generation's uranium concentrate requirements from 2016 through 2020 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.

## **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 completed merger with PHI 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 \$11 billion by the end of 2020. 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 prudently and 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 our 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, 2016, Generation has currently approved plans to invest a total of approximately \$2 billion in 2016 through 2018 on capital growth projects (primarily new plant construction and distributed generation).

## **Liquidity**

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,

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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.

The Registrants have access to unsecured revolving credit facilities with aggregate bank commitments of \$9.0 billion. Generation also has bilateral credit facilities with aggregate maximum availability of \$525 million. See Liquidity and Capital Resources Credit Matters Exelon Credit Facilities below.

***Exposure to Worldwide Financial Markets.*** Exelon has exposure to worldwide financial markets including European banks. Disruptions in the European markets could reduce or restrict the Registrants ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of June 30, 2016, approximately 23%, or \$2.2 billion, of the Registrants aggregate total commitments were with European banks. The credit facilities include \$9.5 billion in aggregate total commitments of which \$7.8 billion was available as of June 30, 2016, due to outstanding letters of credit. There was \$150 million of borrowings under the Registrants bilateral credit facilities as of June 30, 2016. See Liquidity and Capital Resources Credit Matters Exelon Credit Facilities for additional information.

### **Tax Matters**

See Note 11 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

### **Environmental Legislative and Regulatory Developments**

Exelon is actively involved in the EPA 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 electric generating units, as set forth in the discussion below. These regulations have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and have resulted in the retirement of older, marginal facilities. Retirements of coal-fired power plants are expected to continue as additional EPA regulations take effect, and as air quality standards are updated and further restrict emissions. Due to its low emission generation portfolio, Generation will not be significantly directly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. Congress that would prohibit or impede the EPA s rulemaking efforts, and it is uncertain whether any of these bills will become law.

***Air Quality.*** In recent years, the EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act applicable to electric generating units. These regulations have resulted in more stringent emissions limits on fossil-fuel electric generating stations as states implement their compliance plans.

***National Ambient Air Quality Standards (NAAQS).*** The EPA continues to review and update its NAAQS for conventional air pollutants relating to ground-level ozone and emissions of particulate matter, SO<sub>2</sub> and NO<sub>x</sub>. Following five years of litigation, the EPA is finalizing the Cross State Air Pollution Rule that requires 28 upwind states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in downwind states.

***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

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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. As such, 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.

**Climate Change.** Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions. In the absence of federal legislation, the EPA is moving forward with the regulation of GHG emissions under the Clean Air Act. In addition, there have been recent developments in the international regulation of GHG emissions pursuant to the United Nations Framework Convention on Climate Change ( UNFCCC or Convention ). See ITEM 1. BUSINESS, Global Climate Change of the Exelon 2015 Form 10-K for further discussion.

**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, Ginna, Gould Street, Handley, Mountain Creek, Mystic 7, Nine Mile Point Unit 1, Oyster Creek, Peach Bottom, Quad Cities, Salem and Wolf Hollow. See ITEM 1. BUSINESS, Water Quality of the Exelon 2015 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 reserves 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 18 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 Regulatory and Legislative Actions**

**NRC Task Force Insights from the 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. The

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NRC and its staff are continuing to evaluate additional requirements. 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. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance for Generation, net of expected co-owner reimbursements, for the period from 2016 through 2019 is expected to be between approximately \$150 million and \$175 million of capital (which includes approximately \$25 million for the CENG plants) and \$25 million of operating expense (which includes approximately \$5 million for the CENG plants). These revised amounts take into consideration the effect of the early plant retirements of Clinton and Quad Cities (see Note 7 – Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information). Generation's current assessments are specific to the Tier 1 recommendations as the NRC has not finalized actions with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input.

***New York Clean Energy Standard (Exelon, Generation).*** On August 1, 2016, the Clean Energy Standard (CES) was approved by the New York Public Service Commission (NYPSC), a component of which includes creation of a Tier 3 Zero Emission Credit (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 by the federal government. 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 CES initially identifies the three plants eligible for the ZEC program to include, for now, the FitzPatrick, Ginna, and Nine Mile Point nuclear facilities. The program specifically provides that Nine Mile Point Units 1 & 2 qualify jointly as a single facility and if either unit permanently ceases operations then both units will no longer qualify for ZEC payments for the remainder of the program. Additionally, the duration of the program beyond the first tranche is conditional upon a buyer purchasing the FitzPatrick facility and taking title prior to September 1, 2018. See Note 7 – Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information relative to Ginna and Nine Mile Point.

***Illinois Low Carbon Portfolio Standard (Exelon, Generation and ComEd).*** In March 2015, the Low Carbon Portfolio Standard (LCPS) was introduced in the Illinois General Assembly. The legislation would require ComEd and Ameren to purchase low carbon energy credits to match 70 percent of the electricity used on the distribution system. The LCPS is a technology-neutral solution, so all generators of zero or low carbon energy would be able to compete in the procurement process, including wind, solar, hydro, clean coal and nuclear. Costs associated with purchasing the low carbon energy credits would be collected from customers. The LCPS proposal includes consumer protections such as a price cap that would limit the impact to a 2.015% increase based off 2009 monthly bills, or about \$2 per month for the average residential electricity customer, similar to the cost cap protection under other clean energy programs in Illinois. The legislation also includes a separate customer rebate provision that would provide a direct bill credit to customers in the event wholesale prices exceed a specified level. The proposed legislation remains pending along with two other major energy bills. Exelon and Generation continue to work with stakeholders on a comprehensive energy package.

***Legislation to Maximize Smart Grid Investments and to Promote a Cleaner and Greener Illinois (Exelon and ComEd).*** In March 2015, legislation was introduced in the Illinois General Assembly that would (1) build



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on ComEd's investment in the Smart Grid to reinforce the resiliency and security of the electrical grid to withstand unexpected challenges, (2) expand energy efficiency programs to reduce energy waste and increase customer savings, (3) further integrate clean renewable energy onto the power system, and (4) introduce a new demand-based rate design for residential customers that would allow for a more equitable sharing of smart grid costs among customers. The legislation also provides for additional funding for customer assistance programs for low-income customers. The proposed legislation is pending and ComEd continues to work with stakeholders.

***Next Generation Energy Plan (Exelon, Generation and ComEd).*** On May 5, 2016, the Next Generation Energy Plan was introduced in the Illinois General Assembly. The legislation contains significant parts of the previously introduced Illinois Low Carbon Portfolio Standard and Legislation to Maximize Smart Grid Investments and to Promote a Cleaner and Greater Illinois, along with new elements. The legislation includes (1) a Zero Emission Standard providing compensation for at-risk nuclear plants that demonstrate their revenues are insufficient to cover their costs, (2) \$1 billion of funding for low-income assistance, including \$650 million for energy efficiency programs, \$250 million in Renewable Energy Resource Funds, \$50 million in Percentage of Income Payment Plan funding and utility bill assistance, and \$50 million in ComEd CARE, (3) \$140 million in new funding for solar development and a new solar rebate to incent solar generation, (4) additional investment at ComEd to enhance reliability and security of the power grid, (5) an expansion of the Renewable Portfolio Standard, and (6) a 50% reduction in the fixed customer charge for energy delivery creating more equitable rates across customers. The proposed legislation is pending and Exelon, Generation, and ComEd continue to work with stakeholders. See Note 7 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information.

***Distribution Formula Rate (Exelon and ComEd).*** On April 13, 2016, ComEd filed its annual distribution formula rate with the ICC, requesting a total increase to the revenue requirement of \$138 million, reflecting an increase of \$139 million for the initial revenue requirement for 2017 and a decrease of \$1 million related to the annual reconciliation for 2015. The filing establishes the revenue requirement used to set the rates that will take effect in January 2017 after the ICC's review and approval, which is due by December 2016. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information related to distribution formula updates.

***2016 Maryland Electric Distribution Rate Case (Exelon, PHI and Pepco).*** On April 19, 2016, Pepco filed an application with the MDPSC requesting an increase of \$127 million to its annual service revenues for electric delivery, based on a requested ROE of 10.6%. The application also seeks recovery of Pepco's regulatory assets associated with its AMI program over a five year period. Any adjustments to rates approved by the MDPSC are expected to take effect in November 2016. Pepco cannot predict how much of the requested increase the MDPSC will approve. In addition to the proposed \$127 million rate increase, Pepco is proposing to continue its Grid Resiliency Program initially approved in July 2013 in connection with Pepco's electric distribution rate case filed in November 2012. Under the Grid Resiliency Program, Pepco is authorized to receive recovery of specific investments as the assets are placed in service through the Grid Resiliency Charge. In connection with the Grid Resiliency Program, Pepco proposes to accelerate improvement to priority feeders and install single-phase reclosing fuse technology by investing \$16 million a year for two years for a total of \$32 million. Pepco cannot predict whether the MDPSC will approve or if it will approve a continuation of Pepco's Grid Resiliency Program proposal.

***2016 Maryland Electric Distribution Base Rates (Exelon, PHI and DPL).*** On July 20, 2016, DPL filed an application with the MDPSC requesting an increase of \$66 million to its electric distribution base rates, based on a requested ROE of 10.6%. The application also seeks recovery of DPL's regulatory assets associated with its AMI program over a five year period. Any adjustments to rates approved by the MDPSC are expected to take effect in February 2017. DPL cannot predict how much of the requested increase the MDPSC will approve. In addition to the proposed \$66 million rate increase, DPL is proposing to continue its Grid Resiliency Program initially approved in September 2013 in connection with DPL's electric distribution rate case filed in February 2013. Under the Grid Resiliency Program, DPL is authorized to receive recovery of specific investments as the

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assets are placed in service through the Grid Resiliency Charge. In connection with the Grid Resiliency Program, DPL proposes to accelerate improvement to priority feeders and install single-phase reclosing fuse technology by investing \$4.6 million a year for two years for a total of \$9.2 million. DPL cannot predict whether the MDPSC will approve a continuation of DPL's Grid Resiliency Program proposal.

**2016 Electric and Natural Gas Distribution Base 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 and \$22 million, respectively, based on a requested ROE of 10.6%. While the DPSC is not required to issue a decision on the application within a specified period of time, Delaware law allows DPL to put into effect \$2.5 million of the rate increase two months after filing the application and the entire requested rate increase seven months after filing, subject to a cap and a refund obligation based on the final DPSC order. DPL cannot predict how much of the requested increase the DPSC will approve.

**2015 Maryland Electric and Natural Gas Distribution Rate Case (Exelon and BGE).** On November 6, 2015, and as amended through the course of the proceeding, BGE filed for electric and natural gas base rate increases with the MDPSC, ultimately requesting annual increases of \$116 million and \$78 million respectively, of which \$104 million and \$37 million, were related to recovery of electric and natural gas smart grid initiative costs, respectively. BGE also proposed to recover an annual increase of approximately \$30 million for Baltimore City underground conduit fees through a surcharge.

On June 3, 2016, the MDPSC issued an order in which the MDPSC found compelling evidence to conclude that BGE's smart grid initiative overall was cost beneficial to customers. However, the June 3 order contained several cost disallowances and adjustments, including not allowing BGE to defer or recover through a surcharge the \$30 million increase in annual Baltimore City underground conduit fees. On June 30, 2016, BGE filed a petition for rehearing of the June 3 order requesting that the MDPSC modify its order to reverse certain decisions including the decision associated with the Baltimore City underground conduit fees. OPC also subsequently filed for a petition for rehearing of the June 3 order.

On July 29, 2016, the MDPSC issued an order on the petitions for rehearing that reversed certain of its prior cost disallowances and adjustments related to the smart grid initiative. Through the combination of the orders, the MDPSC authorized electric and natural gas rate increases of \$44 million and \$48 million, respectively, and an allowed ROE for the electric and natural gas distribution businesses of 9.75% and 9.65%, respectively; and the new electric and natural gas base rates took effect for service rendered on or after June 4, 2016. However, MDPSC's July 29 order on the petition on rehearing still did not allow BGE to defer or recover through a surcharge the increase in Baltimore City underground conduit fees. BGE is evaluating its options as to the outstanding issues in its petition for rehearing. Refer to Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further details on the impact of the ultimate disallowances contained in the orders to BGE.

**2016 Electric Distribution Base 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, based on a requested ROE of 10.6%. Pepco has requested that the DCPSC issue a final decision by May 29, 2017. Any adjustments to its rates approved by the DCPSC are expected to take effect in June 2017. Pepco cannot predict how much of the requested increase the DCPSC will approve.

**2016 New Jersey Electric Distribution Base Rates (Exelon, PHI and ACE).** On March 22, 2016, as supplemented and updated on May 10, 2016, ACE filed an application with the NJBPU requesting an increase of \$85 million (including New Jersey sales and use tax) to its annual service revenues for electric delivery, based on a requested ROE of 10.6%. In addition to the request for base rate relief, ACE has also included a request that the NJBPU approve ACE's five-year grid resiliency initiative known as PowerAhead. As proposed, PowerAhead includes \$176 million of capital investments to advance modernization of the electric grid through energy

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efficiency, increased distributed generation, and resiliency, focused on improving the distribution system's ability to withstand major storm events. A decision is expected in the first half of 2017. ACE cannot predict how much of the requested increase the NJBPU will approve or if it will approve ACE's PowerAhead initiative.

**Transmission Formula Rate (Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE).** For each of the following years, the following total increases/(decreases) were included in ComEd's, BGE's, Pepco's, DPL's and ACE's electric transmission formula rate filings:

Annual Transmission Filings <sup>(a)</sup>	2016				
	ComEd	BGE	Pepco	DPL	ACE
Initial revenue requirement increase <sup>(b)</sup>	\$ 90	\$ 12	\$ 2	\$ 8	\$ 8
Annual reconciliation (decrease) increase	4	3	(10)	(10)	(14)
MAPP abandonment recovery decrease			(15)	(12)	
Total revenue requirement increase (decrease)	\$ 94	\$ 15	\$ (23)	\$ (14)	\$ (6)
Allowed return on rate base <sup>(c)</sup>	8.47%	8.09%	7.88%	7.21%	7.83%
Previously authorized allowed return on rate base <sup>(c)</sup>	8.61%	8.46%	8.36%	7.80%	8.51%
Allowed ROE <sup>(d)</sup>	11.50%	10.50%	10.50%	10.50%	10.50%

(a) All rates are effective June 2016.

(b) For BGE, this excludes the increase in revenue requirement associated with dedicated facilities charges of \$13 million.

(c) Refers to 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.

**Conduit Lease with City of Baltimore (Exelon and BGE).** On September 23, 2015, the Baltimore City Board of Estimates approved an increase in rental fees for access to the Baltimore City underground conduit system effective November 1, 2015, which is expected to result in an increase to Operating and maintenance expense of approximately \$25 million in 2016 subject to an annual increase based on the Consumer Price Index. On October 16, 2015, BGE filed a lawsuit against the City in the Circuit Court for Baltimore City to protect its customers from any improper use by the City of the conduit fee revenues and to place constraints on the City's ability to set the conduit fee in the future.

Among the relief sought by BGE was a preliminary injunction preventing the City from enforcing its substantial increase in the conduit fee rate during the course of the litigation. A hearing was held in the Circuit Court for Baltimore City on December 15, 2015. While BGE's motion for preliminary injunction was denied, the Court's decision was premised upon several important concessions or acknowledgments made by the City in its written papers and at the hearing. Most importantly, the City conceded that it can charge BGE only for the actual costs of conduit maintenance and that a true-up process is required to the extent that the City fails to spend the amount collected for conduit maintenance. On June 28, 2016, the City filed a motion for summary judgment in its favor arguing that there is no genuine dispute as to any material fact and the City is entitled to judgment as a matter of law.

As part of its electric and gas distribution rate case filed on November 6, 2015, and as amended in the first quarter of 2016, BGE proposed to recover the annual increase in conduit fees effective November 1, 2015 of approximately \$30 million through a surcharge. On June 3, 2016, the MDPSC issued a final order which did not allow BGE to recover or defer the \$30 million in annual Baltimore City conduit fees. On June 30, 2016, BGE filed a petition for rehearing of the June 3 order requesting, among other things, that the MDPSC modify its decision to deny recovery of the Baltimore County conduit fees. On July 29, 2016, the MDPSC issued an order on the petitions for rehearing that, among other things, denied BGE's request that it be allowed to defer or recover through a surcharge the increase in Baltimore City underground conduit fees. BGE is evaluating its options concerning recovery of the conduit fees.

**Table of Contents****Employees**

During the first quarter of 2016, the collective bargaining agreement (CBA) between ComEd and IBEW Local 15, which represents the ComEd's System Services Group, was successfully ratified with a five-year extension. In addition, Exelon added 5,174 total employees from its merger with PHI and its subsidiaries, of which 2,725 are covered by CBAs. PHI's utility subsidiaries are parties to five CBAs with four local unions. All of the CBAs were renegotiated in 2014, and were extended through various dates ranging from October 2018 through June 2020.

**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 and BGE's combined 2015 Form 10-K and PHI's, Pepco's, DPL's and ACE's 2015 combined 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, 2016, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2015.

**Results of Operations****Net Income (Loss) Attributable to Common Shareholders by Registrant**

	Three Months Ended June 30,		Favorable (Unfavorable)	Six Months Ended June 30,		Favorable (Unfavorable)
	2016	2015	Variance	2016 <sup>(a)</sup>	2015	Variance
Exelon	\$ 267	\$ 638	\$ (371)	\$ 440	\$ 1,331	\$ (891)
Generation	(8)	398	(406)	302	841	(539)
ComEd	145	99	46	260	189	71
PECO	100	70	30	224	209	15
BGE	31	44	(13)	129	151	(22)
Pepco	49	42	7	(60)	68	(128)
DPL	12	8	4	(60)	40	(100)
ACE	3	6	(3)	(97)	15	(112)

(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	Successor	Predecessor	
	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	March 24, 2016 to June 30, 2016	January 1, 2016 to March 23, 2016	Six Months Ended June 30, 2015
PHI	52	53	(257)	\$ 19	\$ 106

**Table of Contents****Results of Operations – Generation**

	Three Months Ended June 30,		Favorable (Unfavorable)	Six Months Ended June 30,		Favorable (Unfavorable)
	2016	2015	Variance	2016	2015	Variance
<b>Operating revenues</b>	\$ 3,589	\$ 4,232	\$ (643)	\$ 8,329	\$ 10,074	\$ (1,745)
<b>Purchased power and fuel expense</b>	1,577	1,849	272	4,020	5,282	1,262
<b>Revenue net of purchased power and fuel<sup>(a)</sup></b>	2,012	2,383	(371)	4,309	4,792	(483)
<b>Other operating expenses</b>						
Operating and maintenance	1,530	1,308	(222)	2,997	2,619	(378)
Depreciation and amortization	408	255	(153)	697	509	(188)
Taxes other than income	118	124	6	244	246	2
Total other operating expenses	2,056	1,687	(369)	3,938	3,374	(564)
<b>Gain on sales of assets</b>	31	7	24	31	6	25
<b>Operating income</b>	(13)	703	(716)	402	1,424	(1,022)
<b>Other income and (deductions)</b>						
Interest expense, net	(99)	(99)		(196)	(201)	5
Other, net	117	(31)	148	210	62	148
Total other income and (deductions)	18	(130)	148	14	(139)	153
<b>Income before income taxes</b>	5	573	(568)	416	1,285	(869)
<b>Income taxes</b>	(31)	181	212	120	407	287
<b>Equity in losses of unconsolidated affiliates</b>	(8)	(2)	(6)	(11)	(3)	(8)
<b>Net income</b>	28	390	(362)	285	875	(590)
Net income (loss) attributable to noncontrolling interests	36	(8)	(44)	(17)	34	51
<b>Net (loss) income attributable to membership interest</b>	\$ (8)	\$ 398	\$ (406)	\$ 302	\$ 841	\$ (539)

(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 Attributable to Membership Interest**

*Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015.* Generation's net income attributable to membership interest for three months ended June 30, 2016 decreased compared to the same period in 2015, primarily due to lower revenue net of purchased power and fuel expense, higher operating and maintenance expense and higher depreciation and amortization expense. The decrease in revenue net of purchased power and fuel expense primarily relates to lower mark-to-market results in 2016 compared to 2015, lower realized energy prices and the impact of increase nuclear outage days, partially offset by the Ginna Reliability Support Services Agreement, decreased nuclear fuel prices and increased capacity prices. The increase in operating and maintenance expense is primarily related to the announcement of the early retirement of the Clinton and Quad Cities nuclear facilities and impairment of certain wind projects in 2016. The increase in depreciation

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and amortization expense is primarily related to accelerated depreciation and amortization expense related to the announcement of the early plant retirements, increased nuclear decommissioning amortization and increased depreciation expense due to ongoing capital expenditures.

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*Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015.* Generation's net income attributable to membership interest for the six months ended June 30, 2016 decreased compared to the same period in 2015, primarily due to lower revenue net of purchased power and fuel expense, higher operating and maintenance expense and higher depreciation and amortization expense. The decrease in revenue net of purchased power and fuel expense primarily relates to lower mark-to-market results in 2016 compared to 2015, lower realized energy prices and higher oil inventory write downs in 2016 versus 2015, partially offset by the Ginna Reliability Support Services Agreement, decreased nuclear fuel prices, increased capacity prices and decreased nuclear outage days at higher capacity units. The increase in operating and maintenance expense is primarily related to the announcement of the early retirement of the Clinton and Quad Cities nuclear facilities, Upstream asset impairment, and impairment of certain wind projects in 2016. The increase in depreciation and amortization expense is primarily related to accelerated depreciation and amortization expense related to the announcement of the early plant retirements, increased nuclear decommissioning amortization, and increased depreciation expense due to ongoing capital expenditures.

***Revenue 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.

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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



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or results of operations. Further, the following activities are not allocated to a region, and are reported in Other: unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value from mergers and acquisitions; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing 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, 2016 and 2015, Generation's revenue net of purchased power and fuel expense by region were as follows:

	Three months ended June 30,				Six Months Ended June 30,			
	2016	2015	Variance	% Change	2016	2015	Variance	% Change
Mid-Atlantic <sup>(a)</sup>	\$ 828	\$ 892	\$ (64)	(7.2)%	\$ 1,669	\$ 1,679	\$ (10)	(0.6)%
Midwest <sup>(b)</sup>	728	745	(17)	(2.3)%	1,449	1,448	1	0.1%
New England	110	88	22	25.0%	191	246	(55)	(22.4)%
New York	267	145	122	84.1%	395	334	61	18.3%
ERCOT	77	70	7	10.0%	138	125	13	10.4%
Other Power Regions	96	62	34	54.8%	174	108	66	61.1%
Total electric revenue net of purchased power and fuel expense	2,106	2,002	104	5.2%	4,016	3,940	76	1.9%
Proprietary Trading	4	(2)	6	n.m.	6	3	3	100.0%
Mark-to-market gains / (losses)	(304)	235	(539)	n.m.	(201)	397	(598)	(150.6)%
Other <sup>(c)</sup>	206	148	58	39.2%	488	452	36	8.0%
Total revenue net of purchased power and fuel expense	\$ 2,012	\$ 2,383	\$ (371)	(15.6)%	\$ 4,309	\$ 4,792	\$ (483)	(10.1)%

(a) Results of transactions with PECO and BGE are included in the Mid-Atlantic region. As a result of the PHI Merger, for the Successor period March 24, 2016 to June 30, 2016 for the six month ended, results of transactions with Pepco, DPL and ACE are included in the Mid-Atlantic region.

(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. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of a \$12 million and \$14 million decrease to revenue net of purchased power and fuel expense for the three months ended June 30, 2016 and 2015, respectively, and amortization of intangible assets related to commodity contracts recorded at fair value of a \$7 million and \$24 million increase to revenue net of purchased power and fuel expense for the six months ended June 30, 2016 and 2015, respectively.

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Generation's supply sources by region are summarized below:

Supply source (GWh)	Three Months Ended June 30,				Six Months Ended June 30,			
	2016	2015	Variance	% Change	2016	2015	Variance	% Change
<b>Nuclear generation</b>								
Mid-Atlantic <sup>(a)</sup>	15,224	15,619	(395)	(2.5)%	31,432	31,337	95	0.3%
Midwest	23,001	23,448	(447)	(1.9)%	46,663	45,875	788	1.7%
New York <sup>(a)</sup>	4,228	4,738	(510)	(10.8)%	9,160	9,250	(90)	(1.0)%
<b>Total Nuclear Generation</b>	<b>42,453</b>	<b>43,805</b>	<b>(1,352)</b>	<b>(3.1)%</b>	<b>87,255</b>	<b>86,462</b>	<b>793</b>	<b>0.9%</b>
<b>Fossil and Renewables</b>								
Mid-Atlantic	685	750	(65)	(8.7)%	1,583	1,309	274	20.9%
Midwest	324	363	(39)	(10.7)%	773	795	(22)	(2.8)%
New England	2,016	135	1,881	n.m.	3,940	735	3,205	n.m.
New York	1	1		%	2	2		%
ERCOT	1,879	872	1,007	115.5%	3,255	2,294	961	41.9%
Other Power Regions	1,995	2,096	(101)	(4.8)%	4,142	4,069	73	1.8%
<b>Total Fossil and Renewables</b>	<b>6,900</b>	<b>4,217</b>	<b>2,683</b>	<b>63.6%</b>	<b>13,695</b>	<b>9,204</b>	<b>4,491</b>	<b>48.8%</b>
<b>Purchased Power</b>								
Mid-Atlantic	3,131	1,384	1,747	126.2%	6,886	3,208	3,678	114.7%
Midwest	688	407	281	69.0%	1,394	996	398	40.0%
New England	3,782	5,742	(1,960)	(34.1)%	7,937	12,150	(4,213)	(34.7)%
ERCOT	2,259	2,903	(644)	(22.2)%	4,553	5,147	(594)	(11.5)%
Other Power Regions	3,879	4,616	(737)	(16.0)%	6,479	8,374	(1,895)	(22.6)%
<b>Total Purchased Power</b>	<b>13,739</b>	<b>15,052</b>	<b>(1,313)</b>	<b>(8.7)%</b>	<b>27,249</b>	<b>29,875</b>	<b>(2,626)</b>	<b>(8.8)%</b>
<b>Total Supply/Sales by Region<sup>(b)</sup></b>								
Mid-Atlantic <sup>(c)</sup>	19,040	17,753	1,287	7.2%	39,901	35,854	4,047	11.3%
Midwest <sup>(c)</sup>	24,013	24,218	(205)	(0.8)%	48,830	47,666	1,164	2.4%
New England	5,798	5,877	(79)	(1.3)%	11,877	12,885	(1,008)	(7.8)%
New York	4,229	4,739	(510)	(10.8)%	9,162	9,252	(90)	(1.0)%
ERCOT	4,138	3,775	363	9.6%	7,808	7,441	367	4.9%
Other Power Regions	5,874	6,712	(838)	(12.5)%	10,621	12,443	(1,822)	(14.6)%
<b>Total Supply/Sales by Region</b>	<b>63,092</b>	<b>63,074</b>	<b>18</b>	<b>%</b>	<b>128,199</b>	<b>125,541</b>	<b>2,658</b>	<b>2.1%</b>

(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 1,289 GWh and 1,657 GWh for the three months ended June 30, 2016 and 2015, respectively, and 2,509 GWh and 3,465 GWh for the six months ended June 30, 2016 and 2015, respectively.

(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 for the Successor period of March 24, 2016 to June 30, 2016.

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*Mid-Atlantic*

*Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015.* The \$64 million decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic primarily reflects lower realized energy prices and increased nuclear outage days.

*Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015.* The \$10 million decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic primarily reflects lower realized energy prices and higher oil inventory write-downs in 2016, partially offset by decreased nuclear outage days at higher capacity units, increased capacity prices and increased load volumes served.

*Midwest*

*Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015.* The \$17 million decrease in revenue net of purchased power and fuel expense in the Midwest primarily reflects lower realized energy prices and increased nuclear outage days.

*Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015.* The \$1 million increase in revenue net of purchased power and fuel expense in the Midwest primarily reflects decreased nuclear outage days and increased capacity prices, partially offset by lower realized energy prices.

*New England*

*Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015.* The \$22 million increase in revenue net of purchased power and fuel expense in New England was driven by higher realized energy prices and increased capacity prices.

*Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015.* The \$55 million decrease in revenue net of purchased power and fuel expense in New England was driven by lower realized energy prices and higher oil inventory write-downs in 2016, partially offset by increased capacity prices.

*New York*

*Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015.* The \$122 million increase in revenue net of purchased power and fuel expense in New York was primarily due to the approval of the Ginna Reliability Support Service Agreement, partially offset by increased nuclear outage days.

*Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015.* The \$61 million increase in revenue net of purchased power and fuel expense in New York was primarily due to the approval of the Ginna Reliability Support Service Agreement, partially offset by lower realized energy prices.

*ERCOT*

*Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015.* The \$7 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily due to higher realized energy prices and increased output from renewable assets.

*Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015.* The \$13 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily due to higher realized energy prices and increased output from renewable assets.

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*Other Power Regions*

*Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015.* The \$34 million increase in revenue net of purchased power and fuel expense in Other Power Regions was primarily due to higher realized energy prices.

*Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015.* The \$66 million increase in revenue net of purchased power and fuel expense in Other Power Regions was primarily due to higher realized energy prices.

*Proprietary Trading*

*Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015.* The \$6 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, 2016 Compared to Six Months Ended June 30, 2015.* The \$3 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, 2016 Compared to Three Months Ended June 30, 2015.* Mark-to-market losses on economic hedging activities were \$304 million for the three months ended June 30, 2016 compared to gains of \$235 million for the three months ended June 30, 2015. 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, 2016 Compared to Six Months Ended June 30, 2015.* Mark-to-market losses on economic hedging activities were \$201 million for the six months ended June 30, 2016 compared to gains of \$397 million for the six months ended June 30, 2015. 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, 2016 Compared to Three Months Ended June 30, 2015.* The \$58 million increase in other revenue net of purchased power and fuel was primarily due to revenue related to the inclusion of Pepco Energy Services results in 2016 and revenue related to energy efficiency projects.

*Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015.* The \$36 million increase in other revenue net of purchased power and fuel was primarily due to revenue related to the inclusion of Pepco Energy Services results in 2016 and revenue related to energy efficiency projects, partially offset by the amortization of energy contracts recorded at fair value associated with prior acquisitions and decreased gas sales.

*Nuclear Fleet Capacity Factor*

The following table presents nuclear fleet operating data for the three and six months ended June 30, 2016 as compared to the same periods in 2015, 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

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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,	
	2016	2015	2016	2015
Nuclear fleet capacity factor <sup>(a)</sup>	92.3%	93.1%	94.1%	92.9%

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC. Reflects ownership percentage of stations operated by Exelon. *Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015.* The nuclear fleet capacity factor decreased primarily due to nuclear refueling outage timing and higher non-refueling outage days, excluding Salem outages, during the three months ended June 30, 2016 compared to the same period in 2015. For the three months ended June 30, 2016 and 2015, planned refueling outage days totaled 87 and 71, respectively. During the same periods, non-refueling outage days totaled 21 and 18, respectively.

*Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015.* The nuclear fleet capacity factor increased primarily due to fewer refueling and non-refueling outage days, excluding Salem outages, during the six months ended June 30, 2016 compared to the same period in 2015. For the six months ended June 30, 2016 and 2015, planned refueling outage days totaled 157 and 160, respectively. During the same periods, non-refueling outage days totaled 31 and 50, respectively.

**Operating and Maintenance**

The changes in operating and maintenance expense for the three and six months ended June 30, 2016 as compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Labor, other benefits, contracting, materials	\$ 31	\$ 39
Nuclear refueling outage costs, including the co-owned Salem plants <sup>(a)</sup>	25	18
Corporate allocations <sup>(b)</sup>	(12)	(13)
Allowance for uncollectible accounts	3	3
Merger and integration costs <sup>(c)</sup>	(4)	
Merger commitments		3
Plant retirements and divestitures <sup>(d)</sup>	127	127
Pension and non-pension postretirement benefits expense <sup>(e)</sup>	(13)	(24)
Midwest Generation bankruptcy recoveries <sup>(f)</sup>		10
Impairment of long-lived assets <sup>(g)</sup>	37	157
Cost management program <sup>(h)</sup>	6	24
Other	22	34
Increase in operating and maintenance expense	\$ 222	\$ 378

(a) Primarily reflects the unfavorable impact of the timing and extended duration of an outage at the Salem nuclear power plant for the three and six months ended June 30, 2016.

(b) Reflects a decreased share of corporate allocated costs.

(c) Reflects certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses, integration activities, upfront credit facilities fees, and the PHI acquisition.

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- (d) Represents the announcement of the early retirement of Generation 3 Clinton and Quad Cities nuclear facilities in 2016.
- (e) Reflects favorable impact of higher pension and OPEB discount rates in 2016.

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- (f) Reflects a 2015 benefit for the favorable settlement of a long-term railcar lease agreement pursuant to the Midwest Generation bankruptcy.  
 (g) Primarily relates to the impairment of Upstream assets and certain wind projects at Generation in 2016.  
 (h) Represents the 2016 severance expense and reorganization costs related to a cost management program.

**Depreciation and Amortization**

Depreciation and amortization expense for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015 increased primarily due to accelerated depreciation related to the announcement of the early plant retirements, increased nuclear decommissioning amortization, and increased depreciation expense due to ongoing capital expenditures.

**Taxes Other Than Income**

Taxes other than income for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015 remained relatively stable.

**Gain on Sales of Assets**

Gain on sales of assets for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015 increased as a result of the gain associated with Generation's sale of the New Boston generating site.

**Interest Expense, net**

Interest expense, net for three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015 remained relatively stable.

**Other, Net**

Other, net for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015 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 \$26 million and \$(12) million for the three months ended June 30, 2016 and 2015, respectively, and \$46 million and \$10 million for the six months ended June 30, 2016 and 2015, 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, 2016 and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net unrealized gains (losses) on decommissioning trust funds	\$ 48	\$ (96)	\$ 100	\$ (56)
Net realized gains on sale of decommissioning trust funds	12	50	14	56

**Equity in Losses of Unconsolidated Affiliates**

Equity in losses of unconsolidated affiliates for the three and six months ended June 30, 2016 compared to the three and six months ended June 30, 2015 remained relatively stable.

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Generation s effective income tax rate was (620.0)% and 28.8% for the three and six months ended June 30, 2016, respectively, compared to 31.6% and 31.7% for the same periods during 2015. 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
	2016	2015		2016	2015	
<b>Operating revenues</b>	\$ 1,286	\$ 1,148	\$ 138	\$ 2,535	\$ 2,333	\$ 202
<b>Purchased power expense</b>	339	275	(64)	686	601	(85)
<b>Revenue net of purchased power expense<sup>(a)(b)</sup></b>	947	873	74	1,849	1,732	117
<b>Other operating expenses</b>						
Operating and maintenance	368	384	16	736	762	26
Depreciation and amortization	190	177	(13)	379	352	(27)
Taxes other than income	65	69	4	141	146	5
Total other operating expenses	623	630	7	1,256	1,260	4
<b>Gain on sales of assets</b>				5		5
<b>Operating income</b>	324	243	81	598	472	126
<b>Other income and (deductions)</b>						
Interest expense, net	(91)	(81)	(10)	(177)	(165)	(12)
Other, net	3	5	(2)	7	9	(2)
Total other income and (deductions)	(88)	(76)	(12)	(170)	(156)	(14)
<b>Income before income taxes</b>	236	167	69	428	316	112
<b>Income taxes</b>	91	68	(23)	168	127	(41)
<b>Net income</b>	\$ 145	\$ 99	\$ 46	\$ 260	\$ 189	\$ 71

(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**



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*Three months ended June 30, 2016 Compared to Three months ended June 30, 2015.* ComEd's net income for the three months ended June 30, 2016 was higher than the same period in 2015, primarily due to increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment, partially offset by lower allowed electric distribution ROE) and favorable weather.

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*Six months ended June 30, 2016 Compared to Six months ended June 30, 2015.* ComEd's net income for the six months ended June 30, 2016 was higher than the same period in 2015, primarily due to increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment, partially offset by lower allowed electric distribution ROE).

**Operating Revenue Net of Purchased Power Expense**

There are certain drivers of Operating revenue that are fully offset by their impact on Purchased power expense, such as commodity procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on Revenue net of purchased power expense. See Note 3 Regulatory Matters of the Exelon 2015 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 revenue 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, 2016 and 2015, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	73%	79%	73%	78%

Retail customers purchasing electric generation from competitive electric generation suppliers at June 30, 2016 and 2015 consisted of the following:

	June 30, 2016		June 30, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
	1,605,100	41%	2,268,000	58%

Under an Illinois law allowing municipalities to arrange the purchase of electricity for their participating residents, the City of Chicago previously participated in ComEd's customer choice program and arranged the purchase of electricity from Constellation (formerly Integrys), for those participating residents. In September 2015, the City of Chicago discontinued its participation in the customer choice program and many of those participating residents resumed their purchase of electricity from ComEd. ComEd's Operating revenue has increased as a result of the City of Chicago switching, but that increase is fully offset in Purchased power expense.

The changes in ComEd's Revenue net of purchased power expense for the three and six months ended June 30, 2016, compared to the same periods in 2015 consisted of the following:

	Three Months Ended June 30, 2016 Increase (Decrease)	Six Months Ended June 30, 2016 Increase (Decrease)
Weather	\$ 23	\$ 3
Volume	1	(3)
Electric distribution revenue	22	66
Transmission revenue	31	68
Regulatory required programs	2	(16)
Uncollectible accounts recovery, net	(4)	(17)
Pricing and customer mix	(5)	6

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Other		4		10
Total increase		\$ 74		\$ 117

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*Weather.* 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. For the three and six months ended June 30, 2016, favorable weather conditions increased Operating revenue net of purchased power expense when compared to the same periods in 2015.

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, 2016 and 2015, consisted of the following:

Heating and Cooling Degree-Days Three Months Ended June 30,	2016	2015	Normal	% Change	
				2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	755	686	765	10.1%	(1.3)%
Cooling Degree-Days	290	171	218	69.6%	33.0%
<b>Six Months Ended June 30,</b>					
Heating Degree-Days	3,655	4,318	3,929	(15.4)%	(7.0)%
Cooling Degree-Days	290	171	218	69.6%	33.0%

*Volume.* For the three months ended June 30, 2016, Revenue net of purchased power expense increased as a result of higher delivery volume, exclusive of the effects of weather, reflecting increased average usage per residential customer as compared to the same period in 2015.

For the six months ended June 30, 2016, Revenue net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, reflecting decreased average usage per residential customer primarily due to the impacts of energy efficiency programs, as compared to the same period in 2015.

*Electric Distribution Revenue.* EIMA provides for a performance-based formula rate tariff, 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, allowed ROE, and other billing determinants. ComEd's allowed ROE is the annual average rate on 30-year treasury notes plus 580 basis points, subject to a collar of plus or minus 50 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on revenue. During the three and six months ended June 30, 2016, ComEd recorded increased electric distribution revenue primarily due to increased capital investment and Depreciation and amortization expense, partially offset by lower allowed ROE due to a decrease in treasury rates. See Operating and maintenance expense and 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, investments being recovered and other billing determinants, such as the highest daily peak load from the previous calendar year. For the three and six months ended June 30, 2016, ComEd recorded increased transmission revenue due to increased capital investment, higher Depreciation and amortization expense and increased wholesale transmission revenue as compared to the same period in 2015.

*Regulatory Required Programs.* This represents the change in Operating revenue collected under approved 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.

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*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.

*Pricing and Customer Mix.* For the three months ended June 30, 2016, the decrease in Revenue net of purchased power as a result of pricing and customer mix is primarily attributable to lower overall effective rates due to increased usage across all major customer classes and change in customer mix for the three months ended June 30, 2016, as compared to the same period in 2015.

For the six months ended June 30, 2016, the increase in Revenue net of purchased power as a result of pricing and customer mix is primarily attributable to higher overall effective rates due to decreased usage across all major customer classes as compared to the same period in 2015.

*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.

**Operating and Maintenance Expense**

	Three Months Ended June 30,		Increase (Decrease)	Six Months Ended June 30,		Increase (Decrease)
	2016	2015		2016	2015	
Operating and maintenance expense - baseline	\$ 320	\$ 338	\$ (18)	\$ 649	\$ 659	\$ (10)
Operating and maintenance expense - regulatory required programs <sup>(a)</sup>	48	46	\$ 2	87	103	(16)
<b>Total operating and maintenance expense</b>	<b>\$ 368</b>	<b>\$ 384</b>	<b>\$ (16)</b>	<b>\$ 736</b>	<b>\$ 762</b>	<b>\$ (26)</b>

(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 revenue.

The changes in Operating and maintenance expense for the three and six months ended June 30, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30, 2016 Increase (Decrease)	Six Months Ended June 30, 2016 Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	\$ (4)	\$ (4)
Pension and non-pension postretirement benefits expense <sup>(a)</sup>	(6)	(10)
Storm-related costs	(3)	6
Uncollectible accounts expense - provision <sup>(b)</sup>	1	1
Uncollectible accounts expense - recovery, net <sup>(b)</sup>	(5)	(18)
BSC allocations <sup>(c)</sup>	4	21
Other	(5)	(6)
	(18)	(10)
Regulatory required programs		
Energy efficiency and demand response programs	2	(16)
	2	(16)

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Total increase (decrease)	\$	(16)	\$	(26)
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(a) Primarily reflects the favorable impact of higher assumed pension and OPEB discount rates in 2016.

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(b) 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, 2016, 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 revenue for the periods presented.

(c) Primarily reflects increased information technology support services from BSC during 2016.

**Depreciation and Amortization Expense**

The increase in Depreciation and amortization expense during the three and six months ended June 30, 2016, compared to the same periods in 2015, consisted of the following:

	<b>Three Months Ended June 30, 2016 Increase (Decrease)</b>	<b>Six Months Ended June 30, 2016 Increase (Decrease)</b>
Depreciation expense <sup>(a)</sup>	\$ 14	\$ 27
Regulatory asset amortization	(4)	(6)
Other	3	6
Total increase	\$ 13	\$ 27

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

**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 taxes decreased during the three and six months ended June 30, 2016, compared to the same periods in 2015, due to a reduction in a state utility tax, which is completely offset above in Operating revenues.

**Gain on Sales of Assets**

The increase in Gain on sales of assets during the six months ended June 30, 2016, compared to the same period in 2015, 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, 2016, compared to the same periods in 2015, consisted of the following:

	<b>Three Months Ended June 30, 2016 Increase (Decrease)</b>	<b>Six Months Ended June 30, 2016 Increase (Decrease)</b>
Interest expense related to uncertain tax positions	\$ 4	\$ 4
Interest expense on debt (including financing trusts)	5	9
Other	1	(1)
Increase in interest expense, net	\$ 10	\$ 12

**Effective Income Tax Rate**

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ComEd's effective income tax rate was 38.6% and 40.7% for the three months ended June 30, 2016 and 2015, respectively. ComEd's effective income tax rate was 39.3% and 40.2% for the six months ended June 30, 2016 and 2015, 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.



**Table of Contents****ComEd Electric Operating Statistics and Revenue Detail**

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30,			Weather-Normal		Six Months Ended June 30,			Weather-Normal	
	2016	2015	% Change	% Change	2016	2015	% Change	% Change		
<b>Retail Deliveries<sup>(a)</sup></b>										
Residential	6,349	5,685	11.7%	1.2%	12,725	12,682	0.3%	(0.8)%		
Small commercial & industrial	7,735	7,566	2.2%	0.2%	15,615	15,727	(0.7)%	%		
Large commercial & industrial	6,736	6,680	0.8%	(0.5)%	13,493	13,557	(0.5)%	0.4%		
Public authorities & electric railroads	277	290	(4.5)%	(4.5)%	639	669	(4.5)%	(2.4)%		
Total retail deliveries	21,097	20,221	4.3%	0.2%	42,472	42,635	(0.4)%	(0.1)%		

Number of Electric Customers	As of June 30,	
	2016	2015
Residential	3,570,528	3,511,058
Small commercial & industrial	372,354	369,255
Large commercial & industrial	1,972	1,976
Public authorities & electric railroads	4,749	4,833
Total	3,949,603	3,887,122

Electric Revenue	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	% Change	2016	2015	% Change
<b>Retail Sales<sup>(a)</sup></b>						
Residential	\$ 625	\$ 527	18.6%	\$ 1,232	\$ 1,096	12.4%
Small commercial & industrial	329	330	(0.3)%	651	667	(2.4)%
Large commercial & industrial	116	109	6.4%	224	218	2.8%
Public authorities & electric railroads	11	11	%	23	23	%
Total retail	1,081	977	10.6%	2,130	2,004	6.3%
Other revenue <sup>(b)</sup>	205	171	19.9%	405	329	23.1%
<b>Total electric revenue<sup>(c)</sup></b>	\$ 1,286	\$ 1,148	12.0%	\$ 2,535	\$ 2,333	8.7%

(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 \$1 million for the three months ended June 30, 2016 and 2015, and \$8 million and \$2 million for the six months ended June 30, 2016 and 2015, respectively.

**Table of Contents****Results of Operations PECO**

	Three Months Ended June 30,		Favorable (Unfavorable)	Six Months Ended June 30,		Favorable (Unfavorable)
	2016	2015	Variance	2016	2015	Variance
<b>Operating revenues</b>	\$ 664	\$ 661	\$ 3	\$ 1,505	\$ 1,646	\$ (141)
<b>Purchased power and fuel</b>	217	237	20	537	675	138
<b>Revenue net of purchased power and fuel<sup>(a)</sup></b>	447	424	23	968	971	(3)
<b>Other operating expenses</b>						
Operating and maintenance	190	192	2	405	414	9
Depreciation and amortization	67	69	2	134	131	(3)
Taxes other than income	38	39	1	80	80	
Total other operating expenses	295	300	5	619	625	6
<b>Gain on sales of assets</b>					1	(1)
<b>Operating income</b>	152	124	28	349	347	2
<b>Other income and (deductions)</b>						
Interest expense, net	(31)	(28)	(3)	(62)	(56)	(6)
Other, net	2	1	1	4	3	1
Total other income and (deductions)	(29)	(27)	(2)	(58)	(53)	(5)
<b>Income before income taxes</b>	123	97	26	291	294	(3)
<b>Income taxes</b>	23	27	4	67	85	18
<b>Net income attributable to common shareholder</b>	\$ 100	\$ 70	\$ 30	\$ 224	\$ 209	\$ 15

(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 Attributable to Common Shareholder**

*Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015.* PECO's Net income attributable to common shareholder increased from the same period in 2015, primarily due to an increase in Revenue net of purchased power and fuel expense as a result of increased electric distribution revenue pursuant to the 2015 PAPUC authorized electric distribution rate increase effective January 1, 2016, as well as a lower income tax expense as a result of a cumulative adjustment related to an anticipated gas repairs tax return accounting method change.

*Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015.* PECO's Net income attributable to common shareholder increased from the same period in 2015, primarily due to lower income tax expense as a result of a cumulative adjustment related to an anticipated gas repairs tax return accounting method change.

*Operating 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

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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 mcf sales, respectively) for the three and six months ended June 30, 2016 and 2015, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Electric	72%	71%	70%	69%
Natural Gas	28%	28%	26%	24%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at June 30, 2016 and 2015 consisted of the following:

	June 30, 2016		June 30, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	576,300	36%	552,500	35%
Natural Gas	81,100	16%	81,900	16%

The changes in PECO's operating revenues net of purchased power and fuel expense for the three and six months ended June 30, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended June 30, Increase (Decrease) 2016 vs 2015			Six Months Ended June 30, Increase (Decrease) 2016 vs 2015		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
	Weather	\$ (10)	\$ 4	\$ (6)	\$ (50)	\$ (28)
Volume	5	(2)	3	9	3	12
Pricing	44		44	100	(1)	99
Regulatory required programs	(17)		(17)	(34)		(34)
Other	(1)		(1)	(3)	1	(2)
Total increase (decrease)	\$ 21	\$ 2	\$ 23	\$ 22	\$ (25)	\$ (3)

*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 and six months ended June 30, 2016 compared to the same periods in 2015, Operating revenue net of purchased power and fuel expense was lower due to the impact of unfavorable weather conditions in PECO's service territory.



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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, 2016 compared to the same periods in 2015 and normal weather consisted of the following:

Heating and Cooling Degree-Days Three Months Ended June 30,	2016	2015	Normal	% Change	
				2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	469	330	466	42.1%	0.6%
Cooling Degree-Days	391	513	348	(23.8)%	12.4%
<b>Six Months Ended June 30,</b>					
Heating Degree-Days	2,606	3,264	2,943	(20.2)%	(11.5)%
Cooling Degree-Days	396	513	349	(22.8)%	13.5%

*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, 2016 compared to the same periods in 2015, primarily reflects a shift in the volume profile across classes from lower priced classes to higher priced classes for electric and, for the six months ended June 30, 2016, the impact of moderate economic and customer growth partially offset by energy efficiency initiatives on customer usages for electric and natural gas.

*Pricing.* The increase in Operating revenues net of purchased power and fuel expense as a result of pricing for the three and six months ended June 30, 2016 compared to the same periods in 2015 primarily reflects an increase in electric distribution rates charged to customers. The increase in electric distribution rates was effective January 1, 2016 in accordance with the 2015 PAPUC approved electric distribution rate case settlement. See Note 3 Regulatory Matters of the Combined Notes to the Consolidated Financial Statements in the 2015 Form 10-K for further information.

*Regulatory Required Programs.* This represents the change in Operating revenue collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Income taxes. The decrease in revenue from regulatory required programs for the three and six months ended June 30, 2016 compared to the same periods in 2015 is primarily the result of smart meter costs reflected in base rates in 2016 in accordance with the 2015 PAPUC approved electric distribution rate case settlement effective January 1, 2016 versus through a rider mechanism in 2015. 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,		Increase (Decrease)	Six Months Ended June 30,		Increase (Decrease)
	2016	2015		2016	2015	
Operating and maintenance expense baseline	\$ 165	\$ 162	\$ 3	\$ 361	\$ 359	\$ 2
Operating and maintenance expense regulatory required programs <sup>(a)</sup>	25	30	(5)	44	55	(11)
Total operating and maintenance expense	\$ 190	\$ 192	\$ (2)	\$ 405	\$ 414	\$ (9)

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(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.

The changes in Operating and maintenance expense for the three and six months ended June 30, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	\$ 9	\$ 8
Storm-related costs <sup>(a)</sup>	(17)	(14)
Pension and non-pension postretirement benefits expense	(1)	(2)
PHI merger and integration costs	2	5
BSC allocation <sup>(b)</sup>	8	21
Uncollectible accounts expense	3	(14)
Other	(1)	(2)
	3	2
Regulatory Required Programs		
Smart meter	(8)	(14)
Energy efficiency	4	5
Other	(1)	(2)
	(5)	(11)
Total decrease	\$ (2)	\$ (9)

(a) Reflects lower incremental storm costs in the second quarter of 2016 compared to the second quarter of 2015 as a result of the June 2015 storm.

(b) Primarily reflects increased information technology support services from BSC during 2016.

**Depreciation and Amortization Expense**

The changes in Depreciation and amortization expense for the three and six months ended June 30, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30, Increase (Decrease) 2016 vs. 2015	Six Months Ended June 30, Increase (Decrease) 2016 vs. 2015
Depreciation and amortization expense	\$	\$ 2
Regulatory asset amortization	(2)	1
Total increase (decrease)	\$ (2)	\$ 3

**Taxes Other Than Income**

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Taxes other than income for the three and six months ended June 30, 2016 compared to the same periods in 2015 remained relatively consistent.



**Table of Contents****Interest Expense, Net**

The increase in Interest expense, net for the three and six months ended June 30, 2016 compared to the same periods in 2015 primarily reflects an increase in interest expense due to the issuance of First and Refunding Mortgage Bonds in October 2015.

**Other, Net**

Other, net for the three and six months ended June 30, 2016 remained relatively consistent compared to the same periods in 2015.

**Effective Income Tax Rate**

PECO's effective income tax rate was 18.7% and 27.8% for the three months ended June 30, 2016 and 2015, respectively. PECO's effective income tax rate was 23.0% and 28.9% for the six months ended June 30, 2016 and 2015, respectively. The decrease in the effective income tax rate for the three and six months ended June 30, 2016 compared to the same periods in 2015 is primarily due to a cumulative adjustment related to an anticipated gas repairs tax return accounting method change. 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,			Weather -	Six Months Ended June 30,			Weather -
	2016	2015	% Change	Normal % Change	2016	2015	% Change	Normal % Change
<b>Retail Deliveries<sup>(a)</sup></b>								
Residential	2,909	3,021	(3.7)%	1.1%	6,324	6,989	(9.5)%	1.2%
Small commercial & industrial	1,887	1,925	(2.0)%	(0.3)%	3,912	4,087	(4.3)%	2.3%
Large commercial & industrial	3,770	3,784	(0.4)%	0.3%	7,364	7,517	(2.0)%	(1.4)%
Public authorities & electric railroads	205	214	(4.2)%	(4.2)%	432	443	(2.5)%	(2.5)%
Total retail deliveries	8,771	8,944	(1.9)%	0.3%	18,032	19,036	(5.3)%	0.3%

Number of Electric Customers	As of June 30,	
	2016	2015
Residential	1,449,450	1,437,523
Small commercial & industrial	149,523	148,918
Large commercial & industrial	3,088	3,095
Public authorities & electric railroads	9,813	9,803
Total	1,611,874	1,599,339

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	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	% Change	2016	2015	% Change
<b>Electric Revenue</b>						
<b>Retail Sales<sup>(a)</sup></b>						
Residential	\$ 355	\$ 365	(2.7)%	\$ 766	\$ 815	(6.0)%
Small commercial & industrial	106	102	3.9%	225	217	3.7%
Large commercial & industrial	65	54	20.4%	123	108	13.9%
Public authorities & electric railroads	9	8	12.5%	17	15	13.3%
Total retail	535	529	1.1%	1,131	1,155	(2.1)%
Other revenue <sup>(b)</sup>	52	53	(1.9)%	101	104	(2.9)%
Total electric revenue <sup>(c)</sup>	\$ 587	\$ 582	0.9%	\$ 1,232	\$ 1,259	(2.1)%

(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 and less than \$1 million for the three months ended June 30, 2016 and 2015, respectively, and \$4 million and less than \$1 million for the six months ended June 30, 2016 and 2015, respectively.

**PECO Natural Gas Operating Statistics and Revenue Detail**

	Three Months Ended June 30,			Weather - Normal % Change	Six Months Ended June 30,			Weather - Normal % Change
	2016	2015	% Change		2016	2015	% Change	
<b>Deliveries to Customers (in mmcf)</b>								
<b>Retail Delivery</b>								
Retail sales <sup>(a)</sup>	7,883	7,233	9.0%	(6.7)%	34,994	42,095	(16.9)%	2.2%
Transportation and other	5,906	5,431	8.7%	6.0%	13,602	14,128	(3.7)%	3.3%
Total natural gas deliveries	13,789	12,664	8.9%	(1.5)%	48,596	56,223	(13.6)%	2.5%

	As of June 30,	
	2016	2015
<b>Number of Natural Gas Customers</b>		
Residential	469,230	464,333
Commercial & industrial	43,046	42,603
Total retail	512,276	506,936
Transportation	811	845
Total	513,087	507,781

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	% Change	2016	2015	% Change
<b>Natural Gas Revenue</b>						
<b>Retail Sales</b>						
Retail sales <sup>(a)</sup>	\$ 70	\$ 72	(2.8)%	\$ 256	\$ 368	(30.4)%

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Transportation and other	7	7	%	17	19	(10.5)%
Total natural gas revenues <sup>(b)</sup>	\$ 77	\$ 79	(2.5)%	\$ 273	\$ 387	(29.5)%

(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.

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(b) Includes operating revenues from affiliates totaling less than \$1 million for both the three months ended June 30, 2016 and 2015, and the six months ended June 30, 2016, and \$1 million for the six months ended June 30, 2015.

**Results of Operations BGE**

	Three Months Ended June 30,		Favorable (Unfavorable) Variance	Six Months Ended June 30,		Favorable (Unfavorable) Variance
	2016	2015		2016	2015	
<b>Operating revenues</b>	\$ 680	\$ 628	\$ 52	\$ 1,609	\$ 1,664	\$ (55)
<b>Purchased power and fuel</b>	261	239	(22)	634	726	92
<b>Revenue net of purchased power and fuel<sup>(a)</sup></b>	419	389	30	975	938	37
<b>Other operating expenses</b>						
Operating and maintenance	208	149	(59)	410	331	(79)
Depreciation and amortization	97	87	(10)	206	192	(14)
Taxes other than income	55	54	(1)	114	111	(3)
Total other operating expenses	360	290	(70)	730	634	(96)
<b>Operating income</b>	59	99	(40)	245	304	(59)
<b>Other income and (deductions)</b>						
Interest expense, net	(24)	(24)		(48)	(50)	2
Other, net	5	4	1	11	8	3
Total other income and (deductions)	(19)	(20)	1	(37)	(42)	5
<b>Income before income taxes</b>	40	79	(39)	208	262	(54)
<b>Income taxes</b>	6	32	26	73	105	32
<b>Net income</b>	34	47	(13)	135	157	(22)
Preference stock dividends	3	3		6	6	
<b>Net income attributable to common shareholder</b>	\$ 31	\$ 44	\$ (13)	\$ 129	\$ 151	\$ (22)

(a) BGE evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales and revenue net of purchased fuel expense for gas sales. BGE believes revenue net of purchased power and revenue net of purchased fuel 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, revenue 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, 2016 Compared to Three Months Ended June 30, 2015.* BGE's net income attributable to common shareholder for the three months ended June 30, 2016 was lower than the same period in 2015, primarily due to an increase in Operating and maintenance expense as a result of reducing certain regulatory assets and other long-lived assets stemming from certain cost disallowances contained within the final smart grid rate order issued by the MDPSC in June 2016. The increase in Operating and maintenance expense was partially offset by an increase in Revenue net of purchased power and fuel, primarily as a result of an increase in transmission formula rate revenues, higher electric and natural gas revenues as a result of the distribution rate orders issued by the MDPSC in June 2016, and lower income tax expense driven by lower taxable income.



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*Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015.* BGE's net income attributable to common shareholder for the six months ended June 30, 2016 was lower than the same period in 2015, primarily due to an increase in Operating and maintenance expense as a result of reducing certain regulatory assets and other long-lived assets stemming from certain cost disallowances contained within the final smart grid rate order issued by the MDPSC in June 2016 and increased storm costs. The increase in Operating and maintenance expense was partially offset by an increase in Revenue net of purchased power and fuel, primarily as a result of an increase in transmission formula rate revenues, higher electric and natural gas revenues as a result of the distribution rate orders issued by the MDPSC in June 2016, and lower income tax expense driven by lower taxable income.

**Operating Revenues Net of Purchased Power and Fuel Expense**

There are certain drivers to Operating revenue 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 generation or natural gas supplier. Operating revenue 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 mcf sales, respectively) for the three and six months ended June 30, 2016 and 2015, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Electric	62%	64%	59%	59%
Natural Gas	67%	67%	55%	50%

The number of retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at June 30, 2016 and 2015 consisted of the following:

	June 30, 2016		June 30, 2015	
	Number of Customers	% of total retail customers	Number of customers	% of total retail customers
Electric	337,400	27%	349,400	28%
Natural Gas	151,600	23%	157,300	24%

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The changes in BGE's operating revenues net of purchased power and fuel expense for the three and six months ended June 30, 2016, compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)			Six Months Ended June 30, Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution rate increase	\$ 6	\$ 1	\$ 7	\$ 6	\$ 1	\$ 7
Regulatory required programs	2	1	3			
Transmission revenue	8		8	20		20
Other	11	1	12	15	(5)	10
<b>Total increase (decrease)</b>	<b>\$ 27</b>	<b>\$ 3</b>	<b>\$ 30</b>	<b>\$ 41</b>	<b>\$ (4)</b>	<b>\$ 37</b>

*Distribution Rate Increase.* The increase in distribution rates for the three and six months ended June 30, 2016, compared to the same periods in 2015, was primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective in June 2016 in accordance with the MDPSC approved electric and natural gas distribution rate case orders. 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 changes in actual consumption levels. This allows BGE to recognize revenue at MDPSC-approved levels 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 degree days in BGE's service territory for the three and six months ended June 30, 2016 compared to the same periods in 2015 consisted of the following:

	2016	2015	Normal	% Change	
				2016 vs. 2015	2016 vs. Normal
<b>Heating and Cooling Degree-Days</b>					
<b>Three Months Ended June 30,</b>					
Heating Degree-Days	574	422	509	36.0%	12.8%
Cooling Degree-Days	219	317	257	(30.9)%	(14.8)%
<b>Six Months Ended June 30,</b>					
Heating Degree-Days	2,854	3,372	2,920	(15.4)%	(2.3)%
Cooling Degree-Days	219	317	257	(30.9)%	(14.8)%

*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 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.

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**Transmission Revenue.** Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants. During the three and six months ended June 30, 2016 compared to the same periods in 2015, the increase in transmission revenue was primarily due to increases in capital investment and operating and maintenance expense recoveries. See Operating and Maintenance Expense below and Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

**Other.** Other revenue, which can vary from period to period, includes miscellaneous revenue such as service application and late payment fees.

**Operating and Maintenance Expense**

The changes in operating and maintenance expense for the three and six months ended June 30, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Impairment on long-lived assets and losses on regulatory assets <sup>(a)</sup>	\$ 52	\$ 52
Storm-related costs	1	18
Uncollectible accounts expense <sup>(b)</sup>	5	(7)
City of Baltimore conduit fees <sup>(c)</sup>	8	15
BSC allocations <sup>(d)</sup>	1	7
Other	(8)	(6)
<b>Total increase</b>	<b>\$ 59</b>	<b>\$ 79</b>

(a) See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

(b) Uncollectible accounts increased primarily due to the impact of favorable second quarter weather conditions for the three months ended June 30, 2016 compared to the same period in 2015. Uncollectible accounts decreased primarily due to milder weather and improved customer behavior for the six months ended June 30, 2016 compared to the same periods in 2015.

(c) City of Baltimore conduit fees increased for the three and six months ended June 30, 2016 compared to the same periods in 2015 as a result of increased rental fees assessed by the City of Baltimore. See Executive Overview Environmental Legislative and Regulatory Developments above and Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

(d) Primarily reflects increased information technology support services from BSC during 2016.

**Depreciation and Amortization**

The changes in depreciation and amortization expense for the three and six months ended June 30, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Depreciation expense <sup>(a)</sup>	\$ 2	\$ 7
Regulatory asset amortization <sup>(b)</sup>	8	7
<b>Total increase</b>	<b>\$ 10</b>	<b>\$ 14</b>



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- (a) Depreciation expense increased due to ongoing capital expenditures.
- (b) Regulatory asset amortization increased for the three and six months ended June 30, 2016 compared to the same periods in 2015 primarily due to an increase in regulatory asset amortization related to energy efficiency programs and recovery

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of the AMI programs under the final electric and natural gas distribution rate case order issued by the MDPSC in June 2016. 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, 2016 compared to the same periods in 2015 remained relatively consistent.

**Interest Expense, Net**

Interest expense, net remained relatively consistent during the three and six months ended June 30, 2016, compared to the same periods in 2015.

**Effective Income Tax Rate**

BGE's effective income tax rate was 15.0% and 40.5% for the three months ended June 30, 2016 and 2015, respectively. BGE's effective income tax rate was 35.1% and 40.1% for the six months ended June 30, 2016 and 2015, respectively. The decrease in the effective income tax rate for the three and six months ended June 30, 2016 compared to the same periods in 2015, is primarily due a lower taxable income and a cumulative adjustment to tax expense pending anticipated recovery from transmission customers. 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.

**BGE Electric Operating Statistics and Revenue Detail**

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30,			Weather - Normal % Change	Six Months Ended June 30,			Weather - Normal % Change
	2016	2015	% Change		2016	2015	% Change	
<b>Retail Deliveries<sup>(a)</sup></b>								
Residential	2,616	2,635	(0.7)%	n.m.	6,095	6,808	(10.5)%	n.m.
Small commercial & industrial	692	780	(11.3)%	n.m.	1,466	1,625	(9.8)%	n.m.
Large commercial & industrial	3,417	3,467	(1.4)%	n.m.	6,635	6,906	(3.9)%	n.m.
Public authorities & electric railroads	72	74	(2.7)%	n.m.	143	149	(4.0)%	n.m.
<b>Total electric deliveries</b>	<b>6,797</b>	<b>6,956</b>	<b>(2.3)%</b>	<b>n.m.</b>	<b>14,339</b>	<b>15,488</b>	<b>(7.4)%</b>	<b>n.m.</b>
	<b>As of June 30,</b>							
<b>Number of Electric Customers</b>	<b>2016</b>	<b>2015</b>						
Residential	1,142,073	1,132,325						
Small commercial & industrial	112,980	112,951						
Large commercial & industrial	11,980	11,820						
Public authorities & electric railroads	281	286						
<b>Total</b>	<b>1,267,314</b>	<b>1,257,382</b>						

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Electric Revenue	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	% Change	2016	2015	% Change
<b>Retail Sales<sup>(a)</sup></b>						
Residential	\$ 324	\$ 303	6.9%	\$ 753	\$ 752	0.1%
Small commercial & industrial	65	61	6.6%	137	137	%
Large commercial & industrial	115	109	5.5%	215	229	(6.1)%
Public authorities & electric railroads	9	8	12.5%	18	16	12.5%
Total retail	513	481	6.7%	1,123	1,134	(1.0)%
Other revenue <sup>(b)</sup>	71	60	18.3%	141	120	17.5%
Total electric revenue	\$ 584	\$ 541	7.9%	\$ 1,264	\$ 1,254	0.8%

(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) Includes operating revenues from affiliates totaling \$2 million and \$4 million for the three and six months ended June 30, 2016.

**BGE Natural Gas Operating Statistics and Revenue Detail**

Deliveries to Customers (in mmcf)	Three Months Ended June 30,			Weather - Normal % Change	Six Months Ended June 30,			Weather - Normal % Change
	2016	2015	% Change		2016	2015	% Change	
<b>Retail Deliveries<sup>(a)</sup></b>								
Retail sales	17,672	13,885	27.3%	n.m.	56,256	60,762	(7.4)%	n.m.
Transportation and other <sup>(b)</sup>	271	585	(53.7)%	n.m.	2,767	3,909	(29.2)%	n.m.
Total natural gas deliveries	17,943	14,470	24.0%	n.m.	59,023	64,671	(8.7)%	n.m.

Number of Gas Customers	As of June 30,	
	2016	2015
Residential	618,268	614,168
Commercial & industrial	44,078	44,004
Total	662,346	658,172

Natural Gas Revenue	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	% Change	2016	2015	% Change
<b>Retail Sales<sup>(a)</sup></b>						
Retail sales	\$ 93	\$ 85	9.4%	\$ 331	\$ 384	(13.8)%
Transportation and other <sup>(b)</sup>	3	2	50.0%	14	26	(46.2)%
Total natural gas revenues <sup>(c)</sup>	\$ 96	\$ 87	10.3%	\$ 345	\$ 410	(15.9)%

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- (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 271 mmcfs (\$2 million) and 585 mmcfs (\$3 million) for the three months ended June 30, 2016 and 2015, respectively. Transportation and other gas revenue includes off-system revenue of 2,767 mmcfs (\$11 million) and 3,909 mmcfs (\$25 million) for the six months ended June 30, 2016 and 2015, respectively.
- (c) Includes operating revenues from affiliates totaling \$2 million and \$1 million for the three months ended June 30, 2016 and 2015, respectively, and \$5 million and \$8 million for the six months ended June 30, 2016 and 2015, respectively.

**Table of Contents****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 20 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 periods represent PHI's results of operations for the three and six months ended June 30, 2015 and the period of January 1, 2016 to March 23, 2016. The Successor reporting periods represent PHI's results of operations for 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.

	<i>Successor</i>	<i>Predecessor</i>	<i>Successor</i>	<i>Predecessor</i>	
	<b>Three Months Ended June 30, 2016</b>	<b>Three Months Ended June 30, 2015</b>	<b>March 24, 2016 to June 30, 2016</b>	<b>January 1, 2016 to March 23, 2016</b>	<b>Six Months Ended June 30, 2015</b>
<b>Operating revenues</b>	\$ 1,066	\$ 1,119	\$ 1,171	\$ 1,153	\$ 2,473
<b>Purchased power and fuel</b>	416	429	454	497	1,067
<b>Revenue net of purchased power and fuel<sup>(a)</sup></b>	650	690	717	656	1,406
<b>Other operating expenses</b>					
Operating and maintenance	246	288	695	294	589
Depreciation and amortization	160	152	174	152	307
Taxes other than income	108	111	123	105	229
Total other operating expenses	514	551	992	551	1,125
<b>Operating income (loss)</b>	136	139	(275)	105	281
<b>Other income and (deductions)</b>					
Interest expense, net	(66)	(71)	(71)	(65)	(140)
Other, net	11	12	12	(4)	21
Total other income and (deductions)	(55)	(59)	(59)	(69)	(119)
<b>Income (loss) before income taxes</b>	81	80	(334)	36	162
<b>Income taxes</b>	29	27	(77)	17	56
<b>Net income (loss) attributable to membership interest/common shareholders</b>	\$ 52	\$ 53	\$ (257)	\$ 19	\$ 106

(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, 2016 Compared to the Predecessor Period Three Months Ended June 30, 2015*

*Net Income Attributable to Common Shareholders*

PHI's net income attributable to common shareholders was \$52 million for the three months ended June 30, 2016 as compared to \$53 million for the three months ended June 30, 2015.

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***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, decreased by \$40 million for the three months ended June 30, 2016 as compared to the three months ended June 30, 2015. The decrease is attributable to the following factors:

Increase of \$15 million at Pepco primarily related to electric distribution revenue increases totaling \$9 million due to customer growth, \$3 million due to an EmPower Maryland rate increase effective February 2015, and \$2 million higher transmission revenue due to a higher rate effective June 1, 2015, partially offset by lower revenue related to the MAPP abandonment recovery period ending March 2016.

Increase of \$13 million at DPL primarily related to electric distribution revenue increases totaling \$4 million due to customer growth, an increase of \$2 million due to an EmPower Maryland rate increase effective February 2015, and \$4 million higher transmission revenue due to a higher rate effective June 1, 2015, partially offset by lower revenue related to the MAPP abandonment recovery period ending March 2016.

Decrease of \$9 million at ACE primarily related to lower average customer usage and lower weather-related sales.

Decrease of \$63 million at PES due to PHI's results of operations including the results of PES in 2015 and not in 2016.

***Operating and Maintenance Expense***

Operating and maintenance expense decreased by \$42 million for the three months ended June 30, 2016 as compared to the three months ended June 30, 2015. The decrease is attributable to the following factors:

Increase of \$8 million at Pepco, DPL and ACE primarily due to \$11 million of higher BSC and PHISCO allocations, \$8 million resulting from a remeasurement of AMI-related regulatory assets, \$4 million due to the write-off of construction work in progress, partially offset by a \$12 million deferral of merger-related costs to a regulatory asset and \$3 million lower labor, contracting and material costs primarily related to the implementation of a new customer information system in 2015.

Increase of \$11 million at Corporate due primarily to inter-company and purchase accounting transactions.

Decrease of \$61 million at PES due to PHI's results of operations including the results of PES in 2015 and not in 2016.

***Depreciation and Amortization Expense***

Depreciation and amortization expense increased by \$8 million primarily due to higher depreciation of \$6 million due to ongoing capital expenditures at Pepco, DPL, and ACE.

***Taxes Other Than Income***

Taxes other than income decreased by \$3 million primarily due to lower utility taxes that are collected and passed through by Pepco and DPL.

***Interest Expense, Net***

Interest expense decreased by \$5 million due to lower corporate interest expense.





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***Other, Net***

Other, net for the three months ended June 30, 2016 remained relatively level compared to the same period in 2015.

***Effective Income Tax Rate***

PHI's effective income tax rates for the three months ended June 30, 2016 and 2015 were 35.8% and 33.8%, 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 March 24, 2016 to June 30, 2016***

PHI's net loss attributable to common shareholders for the Successor period of March 24, 2016 to June 30, 2016 was \$(257) million. There were no significant changes in the underlying trends affecting PHI's 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 attributable to common shareholders 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 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.

***Predecessor Period January 1, 2015 to June 30, 2015***

PHI's net income attributable to common shareholders for the Predecessor period of the six months ended June 30, 2015 was \$106 million. There were no significant changes in the underlying trends affecting PHI's operations during the Predecessor period of the six months ended June 30, 2015 except for the pre-tax recording of \$30 million of implementation and support costs due to the completion of a new customer information system and \$14 million of non-recurring merger-related costs within Operating and maintenance expense.

PHI's effective income tax rate for the six months ended June 30, 2015 was 34.6%. 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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	Three Months Ended June 30,		Favorable (Unfavorable) Variance	Six Months Ended June 30,		Favorable (Unfavorable) Variance
	2016	2015		2016	2015	
<b>Operating revenues</b>	\$ 509	\$ 504	\$ 5	\$ 1,061	\$ 1,049	\$ 12
<b>Purchased power expense</b>	152	162	10	351	373	22
<b>Revenue net of purchased power expense<sup>(a)</sup></b>	357	342	15	710	676	34
<b>Other operating expenses</b>						
Operating and maintenance	109	103	(6)	399	215	(184)
Depreciation and amortization	70	63	(7)	144	125	(19)
Taxes other than income	89	93	4	182	190	8
Total other operating expenses	268	259	(9)	725	530	(195)
<b>Gain on sale of assets</b>	8		8	8		8
<b>Operating income (loss)</b>	97	83	14	(7)	146	(153)
<b>Other income and (deductions)</b>						
Interest expense, net	(31)	(31)		(68)	(61)	(7)
Other, net	6	8	(2)	14	13	1
Total other income and (deductions)	(25)	(23)	(2)	(54)	(48)	(6)
<b>Income (loss) before income taxes</b>	72	60	12	(61)	98	(159)
<b>Income taxes</b>	23	18	(5)	(1)	30	31
<b>Net income (loss) attributable to common shareholder</b>	\$ 49	\$ 42	\$ 7	\$ (60)	\$ 68	\$ (128)

(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) Attributable to Common Shareholder**

*Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015.* Pepco's net income attributable to common shareholder for the three months ended June 30, 2016, was higher than the same period in 2015, primarily due to an increase in revenue net of purchased power expense resulting from customer growth.

*Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015.* Pepco's net loss attributable to common shareholder for the six months ended June 30, 2016, compared unfavorably to Pepco's net income for the same period in 2015, primarily due to an increase in operating and maintenance expense due to merger-related costs.

**Operating Revenue Net of Purchased Power Expense**

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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.

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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, 2016, compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Electric	67%	66%	65%	63%

Retail customers purchasing electric generation from competitive electric generation suppliers at June 30, 2016 and 2015 consisted of the following:

	June 30, 2016		June 30, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	175,657	21%	158,753	20%

Retail deliveries purchased from competitive electric generation suppliers represented 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 and 73% and 70% of Pepco's retail kWh sales to the District of Columbia customers and 61% and 58% of Pepco's retail kWh sales to Maryland customers for the three and six months ended June 30, 2015.

The costs related to default electricity supply are included in Purchased power expense. Operating revenues also 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, 2016 compared to the same period in 2015 consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Volume	\$ 9	\$ 14
Regulatory required programs	3	16
Transmission revenue	2	4
Other	1	
Total increase	\$ 15	\$ 34



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**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, 2016 compared to the same periods in 2015 and normal weather consisted of the following:

	2016	2015	Normal	% Change	
				2016 vs. 2015	2016 vs. Normal
<b>Three Months Ended June 30,</b>					
Heating Degree-Days	397	200	324	98.5%	22.5%
Cooling Degree-Days	452	676	475	(33.1)%	(4.8)%
<b>Six Months Ended June 30,</b>					
Heating Degree-Days	2,407	2,691	2,494	(10.6)%	(3.5)%
Cooling Degree-Days	454	676	478	(32.8)%	(5.0)%

**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, 2016 compared to the same periods in 2015, primarily reflects the impact of economic and customer growth.

**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 Revenue.** Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, 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, 2016 compared to the same periods in 2015 is a result of higher rates effective June 1, 2015 related to increases in transmission plant investment and operating expenses, partially offset by lower revenue related to the MAPP abandonment recovery period ending March 2016.

**Table of Contents****Operating and Maintenance Expense**

		Three Months Ended June 30,		Increase	Six Months Ended June 30,		Increase
		2016	2015	(Decrease)	2016	2015	(Decrease)
Operating and maintenance expense	baseline	\$ 107	\$ 101	\$ 6	\$ 394	\$ 210	\$ 184
Operating and maintenance expense	regulatory required programs <sup>(a)</sup>	2	2		5	5	
<b>Total operating and maintenance expense</b>		<b>\$ 109</b>	<b>\$ 103</b>	<b>\$ 6</b>	<b>\$ 399</b>	<b>\$ 215</b>	<b>\$ 184</b>

(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, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	\$ (3)	\$ 4
Storm-related costs	1	3
Remeasurement of AMI-related regulatory asset	7	7
Deferral of merger-related costs to regulatory asset	(9)	(9)
BSC and PHISCO allocations <sup>(a)</sup>	5	34
Merger commitments <sup>(b)</sup>		139
Other	5	6
<b>Total increase</b>	<b>\$ 6</b>	<b>\$ 184</b>

(a) Primarily related to merger severance and compensation costs.

(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions.

**Depreciation and Amortization Expense**

The changes in depreciation and amortization expense for the three and six months ended June 30, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Depreciation expense <sup>(a)</sup>	\$ 2	\$ 4
Regulatory asset amortization <sup>(b)</sup>	5	16

Other				(1)	
Total increase		\$	7	\$	19

- (a) Depreciation expense increased due to ongoing capital expenditures.
- (b) Regulatory asset amortization increased for the three and six months ended June 30, 2016 compared to the same periods in 2015 primarily due to an EmPower Maryland surcharge rate increase effective February 2015, partially offset by lower amortization of MAPP abandonment costs.



**Table of Contents*****Taxes Other Than Income***

Taxes other than income for the three and six months ended June 30, 2016 compared to the same periods in 2015 decreased primarily due to lower property taxes in Maryland and lower utility taxes that are collected and passed through by Pepco.

***Gain on Sale of Assets***

Gain on sale of assets for the three and six months ended June 30, 2016 compared to the same periods in 2015 increased due to a second quarter 2016 gain recorded from the sale of land.

***Interest Expense, Net***

Interest expense, net for the six months ended June 30, 2016 compared to the same period in 2015 increased \$7 million primarily due to the recording of interest expense for an uncertain tax position in the first quarter of 2016.

***Other, Net***

Other, net for the three months ended June 30, 2016 compared to the same period in 2015 decreased primarily due to lower income from the return on AMI-related regulatory assets.

Other, net for the six months ended June 30, 2016 compared to the same period in 2015 increased primarily due to higher income from AFUDC.

***Effective Income Tax Rate***

Pepco's effective income tax rate was 31.9% and 30.0% for three months ended June 30, 2016 and 2015, respectively. Pepco's effective income tax rate was 1.6% and 30.6% for the six months ended June 30, 2016 and 2015, respectively. 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. As a result of the merger, Pepco recorded an after-tax charge of \$33 million during the six months ended June 30, 2016 as a result of assessment and remeasurement of certain federal and state uncertain tax positions.

***Pepco Electric Operating Statistics and Revenue Detail***

	Three Months Ended June 30,			Weather - Normal % Change	Six Months Ended June 30,			Weather - Normal % Change
	2016	2015	% Change		2016	2015	% Change	
<b>Retail Deliveries to Customers (in GWhs)</b>								
<b>Retail Deliveries<sup>(a)</sup></b>								
Residential	1,760	1,899	(7.3)%	0.8%	3,978	4,489	(11.4)%	(1.6)%
Small commercial & industrial	348	307	13.4%	0.3%	730	771	(5.3)%	(0.5)%
Large commercial & industrial	3,631	3,897	(6.8)%	(0.1)%	7,576	7,505	0.9%	(0.4)%
Public authorities & electric railroads	176	179	(1.7)%	%	364	363	0.3%	(0.4)%
Total retail deliveries	5,915	6,282	(5.8)%	1.0%	12,648	13,128	(3.7)%	(0.8)%
	<b>As of June 30,</b>							
<b>Number of Electric Customers</b>	<b>2016</b>	<b>2015</b>						
Residential	771,541	739,440						
Small commercial & industrial	53,345	53,413						
Large commercial & industrial	21,401	20,515						
Public authorities & electric railroads	127	121						

Total	846,414	813,489
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Electric Revenue	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	% Change	2016	2015	% Change
<b>Retail Sales<sup>(a)</sup></b>						
Residential	\$ 220	\$ 220	%	\$ 476	\$ 486	(2.1)%
Small commercial & industrial	36	36	%	73	73	%
Large commercial & industrial	195	193	1.0%	395	379	4.2%
Public authorities & electric railroads	8	8	%	16	16	%
Total retail	459	457	0.4%	960	954	0.6%
Other revenue <sup>(b)</sup>	50	47	6.4%	101	95	6.3%
Total electric revenue <sup>(c)</sup>	\$ 509	\$ 504	1.0%	\$ 1,061	\$ 1,049	1.1%

(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, 2016 and 2015, respectively, and \$3 million and \$2 million for the six months ended June 30, 2016 and 2015, respectively.

**Results of Operations DPL**

	Three Months Ended June 30,		Favorable (Unfavorable) Variance	Six Months Ended June 30,		Favorable (Unfavorable) Variance
	2016	2015		2016	2015	
<b>Operating revenues</b>	\$ 281	\$ 271	\$ 10	\$ 643	\$ 691	\$ (48)
<b>Purchased power and fuel</b>	122	125	3	298	350	52
<b>Revenue net of purchased power and fuel<sup>(a)</sup></b>	159	146	13	345	341	4
<b>Other operating expenses</b>						
Operating and maintenance	78	75	(3)	283	157	(126)
Depreciation, amortization and accretion	38	35	(3)	76	74	(2)
Taxes other than income	13	12	(1)	28	24	(4)
Total other operating expenses	129	122	(7)	387	255	(132)
<b>Operating income (loss)</b>	30	24	6	(42)	86	(128)
<b>Other income and (deductions)</b>						
Interest expense, net	(13)	(13)		(25)	(25)	
Other, net	3	2	1	6	5	1
Total other income and (deductions)	(10)	(11)	1	(19)	(20)	1
<b>Income (loss) before income taxes</b>	20	13	7	(61)	66	(127)
<b>Income taxes</b>	8	5	(3)	(1)	26	27
<b>Net income (loss) attributable to common shareholder</b>	\$ 12	\$ 8	\$ 4	\$ (60)	\$ 40	\$ (100)

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- (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

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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) Attributable to Common Shareholder**

*Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015.* DPL's net income attributable to common shareholder for the three months ended June 30, 2016, was higher than the same period in 2015 as a result of an increase in revenue net of purchased power expense primarily resulting from customer growth and higher transmission revenue offset by increases in various operating expenses discussed below.

*Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015.* DPL's net loss attributable to common shareholder for the six months ended June 30, 2016, compared unfavorably to DPL's net income for the same period in 2015, primarily due to an increase in operating and maintenance expense due to merger-related costs.

**Operating Revenue 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, 2016 and 2015, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Electric	56%	57%	52%	48%
Natural Gas	39%	42%	29%	27%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at June 30, 2016 and 2015 consisted of the following:

	June 30, 2016		June 30, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	76,709	14.9%	77,004	14.9%
Natural Gas	157	0.1%	161	0.1%

Retail deliveries purchased from competitive electric generation suppliers represented 57% and 54% of DPL's retail kWh sales to Delaware customers and 52% and 48% of DPL retail kWh sales to Maryland customers for the three and six months ended June 30, 2016 and 59% and 50% and to Delaware customers and 54% and 45% and to Maryland customers for the three and six months ended June 30, 2015.

The costs related to default electricity supply are included in Purchased power and fuel. Operating revenues also include transmission enhancement credits that DPL receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

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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 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 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, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended June 30			Six Months Ended June 30		
	Increase (Decrease)			Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	\$ (1)	\$ 3	\$ 2	\$ (8)	\$ (5)	\$ (13)
Volume	4		4	6	2	8
Regulatory required programs	2		2	1		1
Transmission revenue	4		4	7		7
Other	1		1	1		1
Total increase (decrease)	\$ 10	\$ 3	\$ 13	\$ 7	\$ (3)	\$ 4

*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.

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*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 months ended June 30, 2016 compared to the same period in 2015, operating revenue net of purchased power and fuel expense was higher due to the impact of favorable weather conditions in DPL's service territory. During the six months ended June 30, 2016 compared to the same period in 2015, operating revenue net of purchased power and fuel expense was lower due to the impact of unfavorable winter 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, 2016 compared to the same periods in 2015 and normal weather consisted of the following:

Three Months Ended June 30,	2016	2015	Normal	% Change	
				2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	551	408	490	35.0%	12.4%
Cooling Degree-Days	304	418	327	(27.3)%	(7.0)%
<b>Six Months Ended June 30,</b>					
Heating Degree-Days	2,798	3,273	2,939	(14.5)%	(4.8)%
Cooling Degree-Days	307	418	328	(26.6)%	(6.4)%

*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, 2016 compared to the same periods in 2015, primarily reflects the impact of moderate economic and customer growth.

*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 Revenue.* Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, 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, 2016 compared to the same periods in 2015 is a result of higher rates effective June 1, 2015 related to increases in transmission plant investment and operating expenses, partially offset by lower revenue related to the MAPP abandonment recovery period ending March 2016.

**Operating and Maintenance Expense**

	Three Months Ended			Six Months Ended		
	2016	2015	Increase (Decrease)	2016	2015	Increase (Decrease)
Operating and maintenance expense baseline	\$ 76	\$ 71	\$ 5	\$ 278	\$ 148	\$ 130
Operating and maintenance expense regulatory required programs <sup>(a)</sup>	2	4	(2)	5	9	(4)
<b>Total operating and maintenance expense</b>	<b>\$ 78</b>	<b>\$ 75</b>	<b>\$ 3</b>	<b>\$ 283</b>	<b>\$ 157</b>	<b>\$ 126</b>

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(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, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	\$ (2)	\$ (1)
Storm-related costs		3
Uncollectible accounts expense	(2)	(3)
Remeasurement of AMI-related regulatory asset	1	1
Deferral of merger-related costs to regulatory asset	(3)	(3)
Write-off of construction work in progress	4	4
BSC and PHISCO allocations <sup>(a)</sup>	3	19
Merger commitments <sup>(b)</sup>		104
Other	4	6
	5	130
Regulatory required programs		
Purchased power administrative costs	(2)	(4)
Total increase	\$ 3	\$ 126

(a) Primarily related to merger severance and compensation costs.

(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions.

**Depreciation, Amortization and Accretion Expense**

The changes in depreciation, amortization and accretion expense for the three and six months ended June 30, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Depreciation expense <sup>(a)</sup>	\$ 2	\$ 4
Regulatory asset amortization <sup>(b)</sup>		1
Delaware renewable energy portfolio standards deferral	1	(3)
Total increase	\$ 3	\$ 2

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



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- (b) Regulatory asset amortization increased for the three and six months ended June 30, 2016 compared to the same periods in 2015 due to an EmPower Maryland surcharge rate increase effective February 2015, partially offset by lower amortization of MAPP abandonment costs.

### ***Taxes Other Than Income***

Taxes other than income for the three and six months ended June 30, 2016 compared to the same periods in 2015 increased primarily due to higher property taxes.

**Table of Contents****Interest Expense, Net**

Interest expense, net for the three and six months ended June 30, 2016 compared to the same periods in 2015 remained relatively constant.

**Other, Net**

Other, net for the three and six months ended June 30, 2016 remained relatively level compared to the same periods in 2015.

**Effective Income Tax Rate**

DPL's effective income tax rate was 40.0% and 38.5% for the three months ended June 30, 2016 and 2015, respectively. DPL's effective income tax rate was 1.6% and 39.4% for the six months ended June 30, 2016 and 2015 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. As a result of the merger, DPL recorded an after-tax charge of \$24 million during the six months ended June 30, 2016 as a result of assessment and remeasurement of certain federal and state uncertain tax positions.

**DPL Electric Operating Statistics and Revenue Detail**

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30,			Weather - Normal % Change	Six Months Ended June 30,			Weather - Normal % Change
	2016	2015	% Change		2016	2015	% Change	
<b>Retail Deliveries<sup>(a)</sup></b>								
Residential	1,038	1,009	2.9%	0.4%	2,465	2,872	(14.2)%	(2.7)%
Small commercial & industrial	532	675	(21.2)%	1.5%	1,104	1,185	(6.8)%	(0.2)%
Large commercial & industrial	1,164	1,159	0.4%	0.2%	2,242	2,267	(1.1)%	(0.3)%
Public authorities & electric railroads	12	10	20.0%	(16.5)%	26	23	13.0%	(8.2)%
Total retail deliveries	2,746	2,853	(3.8)%	0.4%	5,837	6,347	(8.0)%	(1.3)%

Number of Electric Customers	As of June 30,	
	2016	2015
Residential	454,402	453,664
Small commercial & industrial	59,904	59,466
Large commercial & industrial	1,417	1,418
Public authorities & electric railroads	643	645
Total	516,366	515,193

Electric Revenue Retail Sales <sup>(a)</sup>	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	% Change	2016	2015	% Change
Residential	\$ 143	\$ 134	6.7%	\$ 323	\$ 350	(7.7)%
Small commercial & industrial	46	44	4.5%	95	94	1.1%
Large commercial & industrial	25	30	(16.7)%	50	53	(5.7)%
Public authorities & electric railroads	3	3	%	7	6	16.7%
Total retail	217	211	2.8%	475	503	(5.6)%
Other revenue <sup>(b)</sup>	38	35	8.6%	83	77	7.8%
Total electric revenue <sup>(c)</sup>	\$ 255	\$ 246	3.7%	\$ 558	\$ 580	(3.8)%



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- (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, 2016 and 2015, respectively, and \$4 million and \$3 million for the six months ended June 30, 2016 and 2015, respectively.

**DPL Natural Gas Operating Statistics and Revenue Detail**

Retail Deliveries to Customers (in mmcf)	Three Months Ended June 30,			Weather - Normal % Change	Six Months Ended June 30,			Weather - Normal % Change
	2016	2015	% Change		2016	2015	% Change	
<b>Retail Deliveries</b>								
Residential	2,072	1,731	19.7%	7.4%	8,132	9,609	(15.4)%	(3.9)%
Transportation & other	1,321	1,247	5.9%	1.1%	3,289	3,572	(7.9)%	(1)%
Total natural gas deliveries	3,393	2,978	13.9%	4.9%	11,421	13,181	(13.4)%	(3.1)%

Number of Gas Customers	As of June 30,	
	2016	2015
Residential	119,592	118,881
Commercial & industrial	9,669	9,597
Transportation & other	157	161
Total	129,418	128,639

Natural Gas Revenue	Three Months Ended June 30,			% Change	Six Months Ended June 30,		
	2016	2015	% Change		2016	2015	% Change
<b>Retail Sales<sup>(a)</sup></b>							
Retail sales	\$ 21	\$ 20	5.0%	\$ 74	\$ 99	(25.3)%	
Transportation & other <sup>(b)</sup>	5	5	%	11	12	(8.3)%	
Total natural gas revenues	\$ 26	\$ 25	4.0%	\$ 85	\$ 111	(23.4)%	

- (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.

**Table of Contents****Results of Operations ACE**

	Three Months Ended June 30,		Favorable (Unfavorable) Variance	Six Months Ended June 30,		Favorable (Unfavorable) Variance
	2016	2015		2016	2015	
<b>Operating revenues</b>	\$ 270	\$ 285	\$ (15)	\$ 561	\$ 618	\$ (57)
<b>Purchased power expense</b>	141	147	6	298	338	40
<b>Revenue net of purchased power expense<sup>(a)</sup></b>	129	138	(9)	263	280	(17)
<b>Other operating expenses</b>						
Operating and maintenance	68	69	1	280	138	(142)
Depreciation, amortization and accretion	41	43	2	81	86	5
Taxes other than income	2	1	(1)	4	3	(1)
Total other operating expenses	111	113	2	365	227	(138)
<b>Gain on sale of assets</b>	1		1	1		1
<b>Operating income (loss)</b>	19	25	(6)	(101)	53	(154)
<b>Other income and (deductions)</b>						
Interest expense, net	(16)	(16)		(32)	(32)	
Other, net	2	1	1	5	3	2
Total other income and (deductions)	(14)	(15)	1	(27)	(29)	2
<b>Income (loss) before income taxes</b>	5	10	(5)	(128)	24	(152)
<b>Income taxes</b>	2	4	2	(31)	9	40
<b>Net income (loss) attributable to common shareholder</b>	\$ 3	\$ 6	\$ (3)	\$ (97)	\$ 15	\$ (112)

(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) Attributable to Common Shareholder**

*Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015.* ACE's net income attributable to common shareholder for the three months ended June 30, 2016, was lower than the same period in 2015, primarily due to a decrease in operating revenue net of purchased power expense resulting from unfavorable weather-related sales and lower average customer usage.

*Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015.* ACE's net loss attributable to common shareholder for the six months ended June 30, 2016, compared unfavorably to ACE's net income for the same period in 2015, primarily due to an increase in operating and maintenance expense due to merger-related costs.

**Operating Revenue Net of Purchased Power Expense**

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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.

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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, 2016, compared to the same periods in 2015, consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Electric	49%	48%	48%	46%

Retail customers purchasing electric generation from competitive electric generation suppliers at June 30, 2016 and 2015 consisted of the following:

	June 30, 2016		June 30, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	80,325	15%	80,337	15%

The costs related to default electricity supply are included in Purchased power expense. Operating revenues also 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 RTO market of energy and capacity purchased under contracts 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, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended June 30, Increase (Decrease)		Six Months Ended June 30, Increase (Decrease)	
Weather	\$	(2)	\$	(9)
Volume		(8)		(8)
Regulatory required programs		(4)		(9)
Transmission revenues		5		8
Other				1
Total decrease	\$	(9)	\$	(17)

*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 and six months ended June 30, 2016 compared to

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the same periods in 2015, operating revenue net of purchased power and fuel expense was lower due to the impact of unfavorable weather conditions in ACE's service territory.



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For retail customers of ACE, distribution revenues are not decoupled for 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, 2016 compared to the same periods in 2015 consisted of the following:

Three Months Ended June 30,	2016	2015	Normal	% Change	
				2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	651	483	576	34.8%	13.0%
Cooling Degree-Days	258	366	285	(29.5)%	(9.5)%
<b>Six Months Ended June 30,</b>					
Heating Degree-Days	2,921	3,524	3,099	(17.1)%	(5.7)%
Cooling Degree-Days	261	366	286	(28.7)%	(8.7)%

*Volume.* The decrease 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, 2016 compared to the same periods in 2015, primarily reflects the impact of lower average customer usage.

*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 Revenue.* Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, 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, 2016 compared to the same periods in 2015 is a result of higher rates effective June 1, 2015 related to increases in transmission plant investment and operating expenses.

**Operating and Maintenance Expense**

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Increase (Decrease)	2016	2015	Increase (Decrease)
Operating and maintenance expense baseline	\$ 67	\$ 68	\$ (1)	\$ 278	\$ 136	\$ 142
Operating and maintenance expense regulatory required programs <sup>(a)</sup>	1	1		2	2	
<b>Total operating and maintenance expense</b>	<b>\$ 68</b>	<b>\$ 69</b>	<b>\$ (1)</b>	<b>\$ 280</b>	<b>\$ 138</b>	<b>\$ 142</b>

(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.

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The changes in operating and maintenance expense for the three and six months ended June 30, 2016 compared to the same periods in 2015 consisted of the following:

	<b>Three Months Ended June 30, Increase (Decrease)</b>	<b>Six Months Ended June 30, Increase (Decrease)</b>
Baseline		
Labor, other benefits, contracting and materials	\$ (5)	\$ 7
Storm-related costs	1	1
BSC and PHISCO allocations <sup>(a)</sup>	3	16
Uncollectible accounts expense	(1)	1
Merger commitments <sup>(b)</sup>		120
Other	1	(3)
Total (decrease) increase	\$ (1)	\$ 142

(a) Primarily related to merger severance and compensation costs.

(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions.

***Depreciation, Amortization and Accretion Expense***

The changes in depreciation, amortization and accretion expense for the three and six months ended June 30, 2016 compared to the same periods in 2015 consisted of the following:

	<b>Three Months Ended June 30, Increase (Decrease)</b>	<b>Six Months Ended June 30, Increase (Decrease)</b>
Depreciation expense <sup>(a)</sup>	\$ 1	\$ 3
Regulatory asset amortization <sup>(b)</sup>	(3)	(8)
Total decrease	\$ (2)	\$ (5)

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

(b) Regulatory asset amortization decreased for the three and six months ended June 30, 2016 compared to the same periods in 2015 as a result of lower revenue due to a rate decrease effective October 2015 for the ACE Market Transition charge tax.

***Taxes Other Than Income***

Taxes other than income for the three and six months ended June 30, 2016 compared to the same periods in 2015, remained relatively constant.

***Interest Expense, Net***

Interest expense, net for the three and six months ended June 30, 2016 compared to the same periods in 2015 remained relatively constant.

***Other, Net***

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Other, net for the three and six months ended June 30, 2016 compared to the same periods in 2015 increased primarily due to higher income from AFUDC equity.

### *Effective Income Tax Rate*

ACE's effective income tax rate was 40.0% and 40.0% for the three months ended June 30, 2016 and 2015 respectively. ACE's effective income tax rate was 24.2% and 37.5% for the six months ended June 30, 2016 and

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2015 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. As a result of the merger, ACE recorded an after-tax charge of \$23 million during the six months ended June 30, 2016 as a result of assessment and remeasurement of certain federal uncertain tax positions.

**ACE Electric Operating Statistics and Revenue Detail**

	Three Months Ended June 30,			Weather - Normal % Change	Six Months Ended June 30,			Weather - Normal % Change
	2016	2015	% Change		2016	2015	% Change	
<b>Retail Deliveries to Customers (in GWhs)</b>								
<b>Retail Deliveries<sup>(a)</sup></b>								
Residential	814	908	(10.4)%	0.2%	1,752	2,032	(13.8)%	(1.8)%
Small commercial & industrial	283	306	(7.5)%	%	572	611	(6.4)%	(0.9)%
Large commercial & industrial	853	920	(7.3)%	(0.1)%	1,673	1,736	(3.6)%	(0.5)%
Public authorities & electric railroads	9	11	(18.2)%	%	24	23	4.3%	%
Total retail deliveries	1,959	2,145	(8.7)%	0.1%	4,021	4,402	(8.7)%	(1.1)%

	As of June 30,	
	2016	2015
<b>Number of Electric Customers</b>		
Residential	483,044	483,024
Small commercial & industrial	60,928	60,915
Large commercial & industrial	3,806	3,859
Public authorities & electric railroads	594	549
Total	548,372	548,347

	Three Months Ended June 30,			% Change	Six Months Ended June 30,			% Change
	2016	2015	% Change		2016	2015	% Change	
<b>Electric Revenue</b>								
<b>Retail Sales<sup>(a)</sup></b>								
Residential	\$ 131	\$ 147	(10.9)%		\$ 281	\$ 322	(12.7)%	
Small commercial & industrial	39	42	(7.1)%		78	82	(4.9)%	
Large commercial & industrial	50	50	%		101	99	2.0%	
Public authorities & electric railroads	3	3	%		6	6	%	
Total retail	223	242	(7.9)%		466	509	(8.4)%	
Other revenue <sup>(b)</sup>	47	43	9.3%		95	109	(12.8)%	
Total electric revenue <sup>(c)</sup>	\$ 270	\$ 285	(5.3)%		\$ 561	\$ 618	(9.2)%	

(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, 2016 and 2015, respectively, and \$2 million and \$2 million for the six months ended June 30, 2016 and 2015, respectively.



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**Table of Contents****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, 2016. 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, 2016 and 2015. All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

The Registrants' operating and capital expenditure 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 credit facilities with banks which have various expirations dates between December 2016 and May 2021. The Registrants utilize their credit facilities to support their commercial paper programs, and provide for other short-term borrowings, term loans and 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.

***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, natural 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 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2015 Form 10-K for further discussion of regulatory and legal proceedings and proposed legislation. See Note 7 Regulatory Matters and Note 16 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the PHI 2015 Form 10-K.

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The following table provides a summary of the major items affecting Exelon's cash flows from operations for the six months ended June 30, 2016 and 2015:

	Six Months Ended June 30,		
	2016 <sup>(c)</sup>	2015	Variance
Net income	\$ 430	\$ 1,372	\$ (942)
Add (subtract):			
Non-cash operating activities <sup>(a)</sup>	3,992	2,254	1,738
Pension and non-pension postretirement benefit contributions	(258)	(301)	43
Income taxes	470	247	223
Changes in working capital and other noncurrent assets and liabilities <sup>(b)</sup>	(781)	(284)	(497)
Option premiums received, net	(10)	22	(32)
Counterparty collateral received, net	710	659	51
<b>Net cash flows provided by operations</b>	<b>\$ 4,553</b>	<b>\$ 3,969</b>	<b>\$ 584</b>

(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 19 – 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, subject to adjustment for other considerations such as liabilities management and regulatory implications.

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 the event of a fully successful IRS challenge to Exelon's like-kind exchange position, Exelon would be required to either post a bond or pay the tax and interest for the tax years before the court to appeal the decision. If an adverse decision is reached in 2016, the potential tax and after-tax interest, exclusive of penalties, that could become payable may be as much as \$870 million, of which

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approximately \$300 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd



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harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity, and the balance at Exelon. The \$870 million above is comprised of \$1,190 million of tax and interest that could become payable in 2016, reduced by \$320 million of interest benefit that will be realized subsequent to the adverse decision. It is expected that Exelon's remaining tax years affected by the litigation will be settled following a final appellate decision which could take several years.

In April of 2016, Exelon received tax refunds of approximately \$460 million related to IRS positions settled in prior tax years. Of this amount, approximately \$195 million of the refund is attributable to Generation and the remaining \$265 million is attributable to ComEd.

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.

Cash flows from operations for the six months ended June 30, 2016 and 2015 by Registrant were as follows:

	Six Months Ended June 30,	
	2016	2015
Exelon	\$ 4,553	\$ 3,969
Generation	2,387	2,423
ComEd	1,128	800
PECO	339	375
BGE	489	489
Pepco	365	105
DPL	220	115
ACE	208	83

	<i>Successor</i>	<i>Predecessor</i>	
	March 24, 2016 to June 30, 2016	January 1, 2016 to March 23, 2016	Six Months Ended June 30, 2015
PHI	\$ 188	\$ 264	\$ 339

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, 2016 and 2015 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 the exchange or in the OTC markets. During the six months ended June 30, 2016 and 2015, Generation had net collections of counterparty cash collateral of \$720 million and \$682 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, 2016 and 2015, Generation had net (payments)/collections of approximately \$(10) million and \$22 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.



**Table of Contents***ComEd*

During six months ended June 30, 2016 and 2015, ComEd posted approximately \$10 million of cash collateral and had no change to cash collateral at PJM, respectively. ComEd's collateral posted with PJM has increased year over year due to higher RPM credit requirements and higher PJM billings. As of June 30, 2016 and 2015, ComEd had approximately \$41 million and no cash collateral posted with PJM, respectively.

*PHI, Pepco, DPL and ACE*

During the six months ended June 30, 2016, Pepco, DPL and ACE received tax refund allocations from PHI in connection with the Global Tax Settlement of \$147 million, \$56 million and \$167 million, respectively. See Note 11 Income Taxes of the PHI 2015 Form 10-K for additional information.

**Cash Flows from Investing Activities**

Cash flows used in investing activities for the six months ended June 30, 2016 and 2015 by Registrant were as follows:

	Six Months Ended June 30,	
	2016	2015
Exelon	\$ (10,877)	\$ (3,546)
Generation	(2,210)	(1,850)
ComEd	(1,313)	(1,044)
PECO	(291)	(281)
BGE	(375)	(275)
Pepco	(307)	(248)
DPL	(180)	(148)
ACE	(160)	(140)

	<i>Successor</i>	<i>Predecessor</i>	
	March 24, 2016 to June 30, 2016	January 1, 2016 to March 23, 2016	Six Months Ended June 30, 2015
PHI	\$ (350)	\$ (343)	\$ (553)

*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 approximately \$235 million of anticipated expenditures remaining through 2018 to fund anticipated planned capital and operating needs of the associated companies. See Note 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2015 Form 10-K for further details of Generation's equity interests.

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Capital expenditures by Registrant for the six months ended June 30, 2016 and 2015 and projected amounts for the full year 2016 are as follows:

	Projected Full Year 2016 <sup>(a)</sup>	Six Months Ended June 30,	
		2016	2015
Exelon	\$ 8,975	\$ 4,489	\$ 3,460
Generation	3,400	2,051	1,764
ComEd <sup>(b)</sup>	2,575	1,334	1,061
PECO	675	299	289
BGE	850	392	304
Pepco <sup>(c)</sup>	575	256	254
DPL <sup>(c)</sup>	325	182	154
ACE <sup>(c)</sup>	275	164	138
Other <sup>(d)</sup>	125	74	47

	Projected Full Year 2016 <sup>(a)</sup>	Successor March 24, 2016 to June 30, 2016		Predecessor January 1, 2016 to March 23, 2016	
		March 24, 2016 to June 30, 2016	March 23, 2016	Six Months Ended June 30, 2015	
PHI	\$ 1,175	\$ 339	\$ 273	\$ 562	

(a) Total projected capital expenditures do not include adjustments for non-cash activity.

(b) The 2016 projections include approximately \$624 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.

(c) Projected capital expenditures reflect projections after March 23, 2016.

(d) Other primarily consists of corporate operations, BSC and PHISCO.

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

*Generation*

Approximately 32% and 36% of the projected 2016 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 86%, 96%, 100%, 100%, 100% and 100% of the projected 2016 capital expenditures at ComEd, PECO, BGE, Pepco, DPL and ACE, respectively, 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 capital expenditures for continuing projects, ComEd's total expenditures include smart grid/smart meter technology required under EIMA and for PECO, BGE, Pepco, DPL, and ACE, include capital expenditures related to their respective smart meter programs.

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



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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 2016 capital expenditures above reflect capital spending for remediation to be completed through 2017. Pepco, DPL and ACE have substantially completed their assessments and thus do not expect significant capital expenditures related to this guidance in 2016.

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, 2016 and 2015 by Registrant were as follows:

	Six Months Ended June 30,	
	2016	2015
Exelon	\$ 1,469	\$ 3,713
Generation	(235)	(897)
ComEd	854	229
PECO	(140)	(98)
BGE	(118)	(254)
Pepco	64	159
DPL	(30)	35
ACE	100	58

	<i>Successor</i>	<i>Predecessor</i>	
	March 24, 2016 to June 30, 2016	January 1, 2016 to March 23, 2016	Six Months Ended June 30, 2015
PHI	\$ 137	\$ 372	\$ 233

**Debt**

See Note 10 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants' debt issuances.

**Dividends**

Cash dividend payments and distributions during the six months ended June 30, 2016 and 2015 by Registrant were as follows:

	Six Months Ended June 30,	
	2016	2015
Exelon	\$ 582	\$ 537
Generation	111	2,262
ComEd	183	150
PECO	139	139
BGE <sup>(a)</sup>	96	83
Pepco	55	31

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DPL	38	62
ACE	11	12

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	<i>Successor</i> March 24, 2016 to June 30, 2016	<i>Predecessor</i> January 1, 2016 to March 23, 2016 Six Months Ended June 30, 2015
PHI	\$ 124	\$ 137

(a) Includes dividends paid on BGE's preference stock.

Quarterly dividends declared by the Exelon Board of Directors during the six months ended June 30, 2016 and for the third quarter of 2016 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share <sup>(a)</sup>
First Quarter 2016	January 26, 2016	February 12, 2016	March 10, 2016	\$0.310
Second Quarter 2016	April 26, 2016	May 13, 2016	June 10, 2016	\$0.318
Third Quarter 2016	July 26, 2016	August 15, 2016	September 9, 2016	\$0.318

(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, 2016 and 2015 by Registrant were as follows:

	Six Months Ended June 30,	
	2016	2015
Exelon	\$ (798)	\$ 94
Generation	179	15
ComEd	(259)	199
BGE	(2)	(120)
Pepco	(64)	(104)
DPL	(105)	(76)
ACE	(5)	91

	<i>Successor</i> March 24, 2016 to June 30, 2016	<i>Predecessor</i> January 1, 2016 to March 23, 2016 Six Months Ended June 30, 2015
PHI	\$ (837)	\$ 379

*Contributions from Parent/Member*

Contributions received from Parent/Member for the six months ended June 30, 2016 and 2015 by Registrant were as follows:

	Six Months Ended June 30,	
	2016	2015
Generation	\$ 45	\$
ComEd	113 <sup>(a)</sup>	45 <sup>(a)</sup>



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BGE	21 <sup>(a)</sup>	
Pepco	187 <sup>(b)</sup>	112 <sup>(b)</sup>
DPL	113 <sup>(b)</sup>	75 <sup>(b)</sup>
ACE	139 <sup>(b)</sup>	

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	<i>Successor</i>	<i>Predecessor</i>	
		<b>January 1, 2016</b>	
	<b>March 24, 2016 to June 30, 2016</b>	<b>to March 23, 2016</b>	<b>Six Months Ended June 30, 2015</b>
PHI	\$ 1,088 <sup>(a)</sup>	\$	\$

(a) Contribution paid by Exelon.

(b) Contribution paid by PHI.

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

*Redemptions of Preference Stock*

On July 3, 2016, BGE redeemed all 400,000 shares of its outstanding 7.125% Cumulative Preference Stock, 1993 Series and all 600,000 shares of its outstanding 6.99% Cumulative Preference Stock, 1995 Series for \$100 million, plus accrued and unpaid dividends. Following this redemption, BGE has \$90 million of cumulative preference stock remaining, which will likely be redeemed by the end of 2016. See Note 17 Earnings Per Share and Equity of the Combined Notes to Consolidated Financial Statements for further details.

*Other*

For the six months ended June 30, 2016, 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 \$7.8 billion was available as of June 30, 2016, 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 2016 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 2015 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, 2016, 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 \$4.2 billion.

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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, 2016 and available credit facility capacity prior to any incremental collateral at June 30, 2016:

	PJM Credit Policy Collateral	Other Incremental Collateral Required <sup>(a)</sup>	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	\$ 3	\$	\$ 998
PECO	2	26	598
BGE	2	31	600
Pepco			300
DPL	3	9	300
ACE			299

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

**Exelon Credit Facilities**

Exelon, 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. Pepco, DPL and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and short-term notes. 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, 2016:

**Commercial Paper Programs**

Commercial Paper Issuer	Maximum Program Size <sup>(a)(b)</sup>	Outstanding Commercial Paper at June 30, 2016	Average Interest Rate on Commercial Paper Borrowings for the Six Months Ended June 30, 2016
Exelon Corporate	\$ 600	\$	0.70%
Generation	5,300		1.01%
ComEd	1,000	35	0.79%
PECO	600		%
BGE	600	208	0.78%
Pepco	500		0.67%
DPL	500		0.69%
ACE	350		0.65%

(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 and BGE with aggregate commitments of \$50 million, \$34 million, \$34 million and \$5 million, respectively, arranged with minority and community banks located primarily within ComEd's, PECO's and BGE's service territories. These facilities expire on October 14, 2016. These facilities are solely utilized to issue letters of credit. As of June 30, 2016, letters of credit issued under these agreements for Generation, ComEd, PECO and BGE totaled \$7 million, \$14 million, \$21 million and \$2 million, respectively.

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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

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capacity under its credit facility. At June 30, 2016, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit facilities:

**Credit Agreements**

Borrower	Facility Type	Aggregate Bank Commitment <sup>(a)(b)(c)</sup>	Facility Draws	Outstanding Letters of Credit	Available Capacity at June 30, 2016	
					Actual	To Support Additional Commercial Paper <sup>(d)</sup>
Exelon Corporate	Syndicated Revolver	\$ 600	\$	\$ 29	\$ 571	\$ 571
Generation <sup>(e)</sup>	Syndicated Revolver	5,300		1,194	4,106	4,106
Generation	Bilaterals	525	150	319	56	
ComEd	Syndicated Revolver	1,000		2	998	963
PECO	Syndicated Revolver	600		2	598	598
BGE	Syndicated Revolver	600			600	392
Pepco	Syndicated Revolver	300			300	300
DPL	Syndicated Revolver	300			300	300
ACE	Syndicated Revolver	300		1	299	299

(a) Excludes \$123 million of credit facility agreements arranged at minority and community banks at Generation, ComEd, PECO and BGE. These facilities expire on October 14, 2016. These facilities are solely utilized to issue letters of credit. As of June 30, 2016, letters of credit issued under these agreements for Generation, ComEd, PECO and BGE totaled \$7 million, \$14 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 2015 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 \$20 million of borrowed debt on its revolving credit facility.

As of June 30, 2016, there was \$150 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, 2016:

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	<b>Exelon</b>	<b>Generation</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>	<b>Pepco</b>	<b>DPL</b>	<b>ACE</b>
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

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At June 30, 2016, 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	8.92	12.94	7.55	8.94	10.76	5.63	7.56	4.70

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, 2016, are presented in the following table:

Exelon Intercompany Money Pool	During the Three Months Ended June 30, 2016		As of June 30, 2016
	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Exelon Corporate	\$ 1,325	n/a	\$ 1,121
Generation		1,143	(817)
PECO	161		
BSC		379	(333)
PHI Corporate <sup>(a)</sup>	n/a	36	(34)
PCI <sup>(a)</sup>	63		63

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(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, 2016		As of June 30, 2016
	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Contributed (borrowed)			
PHI Corporate	\$ 152	n/a	\$ 25
Pepco			
DPL			
ACE			
PHISCO		152	(25)

**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 and BGE have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in May 2017. PHI, Pepco, DPL and ACE have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in August 2016. 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 <sup>(a)</sup>			Long-term Financing Authority		
	Commission	Expiration Date	Amount (in millions)	Commission	Expiration Date	Amount (in millions)
ComEd <sup>(b)</sup>	FERC	December 31, 2017	\$2,500	ICC	2019	\$2,383
PECO	FERC	December 31, 2017	1,500	PAPUC	December 31, 2018	1,900
BGE	FERC	December 31, 2017	700	MDPSC	N/A	850
Pepco	FERC	June 30, 2018	500	MDPSC / DCPSC	September 25, 2017	550
DPL	FERC	June 30, 2018	500	MDPSC / DPSC	December 31, 2017	300
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, 2016 and has an expiration date of June 1, 2019 and March 1, 2019, respectively.





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**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 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in the Exelon 2015 Form 10-K and Note 16 Commitments and Contingencies of the PHI 2015 Form 10-K for discussion of the Registrants' commitments.

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 Significant Accounting Policies 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 2015 Form 10-K and Management's Discussion and Analysis of Financial Condition and Results of Operations Contractual Obligations and Commercial Commitments and Management's Discussion and Analysis of Financial Condition and Results of Operations Guarantees, Indemnifications and Off-Balance Sheet Arrangements in the PHI 2015 Form 10-K.

**Table of Contents****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 the Registrants' 2015 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 2016 through 2018.

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, 2016, the proportion of expected generation hedged is 97%-100%, 78%-81% and 47%-50% for 2016, 2017 and 2018, 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 for capacity 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, 2016 market conditions and hedged position would be an increase in pre-tax net income of approximately \$5 million for 2016 and decreases of \$205 million and \$475 million, respectively, for 2017 and 2018. 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.

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**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 1,289 GWhs and 2,509 GWhs for the three and six months ended June 30, 2016, respectively, and 1,657 GWhs and 3,465 GWhs for the three and six months ended June 30, 2015, 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, 2016 resulted in pre-tax gains of \$6 million due to net mark-to-market gains of \$2 million and \$4 million realized gains. 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 \$0.2 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 from continuing operations for the six months ended June 30, 2016 of \$4,309 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 58% of Generation's uranium concentrate requirements from 2016 through 2020 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. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information regarding uranium and coal supply agreement matters.

**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 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

**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

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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. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into derivative 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.

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***DPL***

DPL has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the DPSC. The SOS rates charged recover DPL's wholesale power supply costs and include 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. DPL's price risk related to electric supply procurement is limited. DPL locks in fixed prices for all of its SOS requirements through full requirements contracts. 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).

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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, 2015 to June 30, 2016. 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, 2016 and December 31, 2015.

	Generation	ComEd	DPL <sup>(a)</sup>	Exelon <sup>(b)</sup>
Total mark-to-market energy contract net assets (liabilities) at December 31, 2015 <sup>(c)</sup>	\$ 1,753	\$ (247)	\$	\$ 1,506
Total change in fair value during 2016 of contracts recorded in results of operations	(30)			(30)
Reclassification to realized at settlement of contracts recorded in results of operations	(160)			(160)
Changes in fair value – energy derivatives <sup>(d)</sup>		26	3	28
Changes in allocated collateral	(713)		(3)	(715)
Changes in net option premium paid/(received)	10			10
Option premium amortization	17			17
Upfront payment amortizations <sup>(e)</sup>	17			17
Total mark-to-market energy contract net assets (liabilities) at June 30, 2016 <sup>(c)</sup>	\$ 894	\$ (221)	\$	\$ 673

- (a) As of June 30, 2016 and December 31, 2015, PHI's and DPL's mark-to-market derivative asset was fully collateralized resulting in a zero balance. For the predecessor period of January 1, 2016 to March 23, 2016, PHI recorded a \$1 million increase in fair value and \$1 million decrease in allocated collateral related to the exchange-traded futures.
- (b) As a result of the merger, Exelon amounts include PHI and DPL activity from March 24, 2016 to June 30, 2016. For the successor period of March 24, 2016 to June 30, 2016, there was a \$2 million increase in fair value and \$2 million decrease in allocated collateral related to the exchange-traded futures.
- (c) Amounts are shown net of collateral paid to and received from counterparties.
- (d) For ComEd and DPL, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of June 30, 2016, ComEd recorded a \$221 million regulatory asset related to its mark-to-market derivative liabilities with unaffiliated suppliers. For the six months ended June 30, 2016, ComEd also recorded \$15 million of decreases in fair value and realized losses due to settlements of \$11 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers. As of June 30, 2016, DPL recorded a \$1 million regulatory liability related to its mark-to-market derivative liabilities.
- (e) Includes derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums.

**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.

**Table of Contents****Exelon**

	Maturities Within					2021 and Beyond	Total Fair Value
	2016	2017	2018	2019	2020		
Normal Operations, Commodity derivative contracts <sup>(a)(b)</sup> :							
Actively quoted prices (Level 1)	\$ 21	\$ 40	\$ (21)	\$ (25)	\$ (6)	\$ 1	\$ 10
Prices provided by external sources (Level 2)	146	139	(6)	(6)	2		275
Prices based on model or other valuation methods (Level 3) <sup>(c)</sup>	202	248	68	(28)	(17)	(85)	388
<b>Total</b>	<b>\$ 369</b>	<b>\$ 427</b>	<b>\$ 41</b>	<b>\$ (59)</b>	<b>\$ (21)</b>	<b>\$ (84)</b>	<b>\$ 673</b>

(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 \$521 million at June 30, 2016.

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

**Generation**

	Maturities Within					2021 and Beyond	Total Fair Value
	2016	2017	2018	2019	2020		
Normal Operations, Commodity derivative contracts <sup>(a)(b)</sup> :							
Actively quoted prices (Level 1)	\$ 21	\$ 40	\$ (21)	\$ (25)	\$ (6)	\$ 1	\$ 10
Prices provided by external sources (Level 2)	146	139	(6)	(6)	2		275
Prices based on model or other valuation methods (Level 3)	211	266	85	(11)		58	609
<b>Total</b>	<b>\$ 378</b>	<b>\$ 445</b>	<b>\$ 58</b>	<b>\$ (42)</b>	<b>\$ (4)</b>	<b>\$ 59</b>	<b>\$ 894</b>

(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 \$521 million at June 30, 2016.

**ComEd**

	Maturities Within					2021 and Beyond	Total Fair Value
	2016	2017	2018	2019	2020		
Commodity derivative contracts <sup>(a)</sup> :							
Prices based on model or other valuation methods (Level 3)	\$ (9)	\$ (18)	\$ (17)	\$ (17)	\$ (17)	\$ (143)	\$ (221)

(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)**



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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

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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, 2016. 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 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 \$26 million, \$40 million, \$36 million, \$50 million, \$15 million, and \$8 million as of June 30, 2016, respectively.

Rating as of June 30, 2016	Total Exposure Before		Credit Collateral <sup>(a)</sup>	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure			
	Credit	Collateral							
Investment grade	\$	965	\$	12	\$	953	1	\$	356
Non-investment grade		55		24		31			
No external ratings									
Internally rated investment grade		373		1		372			
Internally rated non-investment grade		46		7		39			
Total	\$	1,439	\$	44	\$	1,395	1	\$	356

Rating as of June 30, 2016	Maturity of Credit Risk Exposure				Total Exposure Before Credit Collateral				
	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years						
Investment grade	\$	703	\$	255	\$	7	\$	965	
Non-investment grade		42		13				55	
No external ratings									
Internally rated investment grade		316		36		21		373	
Internally rated non-investment grade		44		2				46	
Total		\$	1,105	\$	306	\$	28	\$	1,439

Net Credit Exposure by Type of Counterparty	As of June 30, 2016	
Financial institutions	\$	96
Investor-owned utilities, marketers, power producers		573
Energy cooperatives and municipalities		696
Other		30
Total	\$	1,395

(a) As of June 30, 2016, credit collateral held from counterparties where Generation had credit exposure included \$9 million of cash and \$35 million of letters of credit.

***ComEd, PECO and BGE***

There have been no significant changes or additions to ComEd's, PECO's, or BGE's exposures to credit risk that are described in ITEM 1A. RISK FACTORS of Exelon's 2015 Annual Report on Form 10-K.

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See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

***PHI, Pepco, DPL and ACE***

There have been no significant changes or additions to PHI s, Pepco s, DPL s or ACE s exposures to credit risk as described in ITEM 1A. RISK FACTORS of PHI s 2015 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, 2016, Generation had cash collateral of \$548 million posted and cash collateral held of \$14 million for external counterparties with derivative positions, of which \$521 million and \$3 million 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, 2016, \$10 million of cash collateral posted 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 18 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, 2016, ComEd held \$1 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 renewable

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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 2015 Exelon Form 10-K for additional information.

### *PECO*

As of June 30, 2016, 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. As of June 30, 2016, BGE was not required to post collateral under its natural gas procurement contracts nor was it holding collateral under its electric supply and 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, 2016, 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, real-time 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 markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot 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 and the Nodal exchange. DPL enters into commodity transactions on ICE. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk.

**Table of Contents*****Long-Term Leases (Exelon)***

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 6 Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for additional information.

**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 Exelon 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, 2016, Exelon had \$800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had \$764 million and \$674 million of notional amounts of floating-to-fixed hedges outstanding, respectively. Assuming the fair value and cash flow 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, 2016. 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)**

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. As of June 30, 2016, 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 \$485 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 2016, 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,

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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, 2016, 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. On March 23, 2016, the merger between Exelon and PHI closed. Exelon is currently in the process of integrating PHI's operations, processes and internal controls. There have been no changes in internal control over financial reporting that occurred during the second quarter of 2016, other than changes resulting from the PHI Merger, 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. See Note 4 Mergers, Acquisitions and Dispositions of the Combined Notes to the Consolidated Financial Statements for further information regarding the PHI acquisition. Exelon's management expects that the controls over financial reporting associated with PHI, Pepco, DPL and ACE from the date of the merger forward will be covered in the year-end assessment.

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**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 2015 Form 10-K, (b) ITEM 3. LEGAL PROCEEDINGS of PHI's 2015 Form 10-K and (c) Notes 5 Regulatory Matters and 18 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**

Exclusive of the *Risks Related to the Pending Merger with PHI* described in Exelon's 2015 Form 10-K in ITEM 1A. RISK FACTORS, Exelon is, and will continue to be, subject to the risks described in Exelon's and PHI's 2015 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 23 of the Combined Notes to Consolidated Financial Statements in Exelon's 2015 Form 10-K and Note 16 of the Notes to Consolidated Financial Statements in PHI's 2015 Form 10-K. As a result of the merger with PHI that closed on March 23, 2016 Exelon is subject to additional risks related to the merger as described below.

**Risks Related to the PHI Merger**

**The merger may not achieve its anticipated results, and Exelon may be unable to integrate the operations of PHI in the manner expected.**

Exelon and PHI entered into the merger agreement with the expectation that the merger will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Exelon and PHI can be integrated in an efficient, effective and timely manner.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of Exelon's businesses, processes and systems or inconsistencies in standards, controls, procedures, practices and policies, any of which could adversely affect the combined company's ability to achieve the anticipated benefits of the merger as and when expected. Exelon may have difficulty addressing possible differences in corporate cultures and management philosophies. Failure to achieve these anticipated benefits could result in increased costs and could adversely affect Exelon's future business, financial condition, operating results and prospects.

**The merger may not be accretive to earnings and may cause dilution to Exelon's earnings per share, which may negatively affect the market price of Exelon's common stock.**

The timing and amount of accretion expected could be significantly adversely affected by a number of uncertainties, including market conditions, risks related to Exelon's businesses and whether the business of PHI is integrated in an efficient and effective manner. Exelon also could encounter additional transaction and integration-related costs, may fail to realize all of the benefits anticipated in the merger or be subject to other factors that affect preliminary estimates. Any of these factors could cause a decrease in Exelon's adjusted earnings per share or decrease or delay the expected accretive effect of the merger and contribute to a decrease in the price of Exelon's common stock.



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**Exelon may incur unexpected transaction fees and merger-related costs in connection with the merger.**

Exelon expects to incur a number of non-recurring expenses associated with completing the merger, as well as expenses related to combining the operations of the two companies. Exelon may incur additional unanticipated costs in the integration of the businesses of Exelon and PHI. Although Exelon expects that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction and merger-related costs over time, the combined company may not achieve this net benefit in the near term, or at all.

**Exelon may encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals for the PHI Merger.**

As a result of the process to obtain regulatory approvals required for the PHI Merger, Exelon is committed to various programs, contributions and investments in several settlement agreements and regulatory approval orders. It is possible that Exelon may encounter delays, unexpected difficulties, or additional costs in meeting these commitments in compliance with the terms of the relevant agreements and orders. Failure to fulfill the commitments in accordance with their terms could result in increased costs or result in penalties or fines that could adversely affect Exelon's financial position and operating results.

**Item 4 Mine Safety Disclosures  
Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE**

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**

<b>No.</b>	<b>Description</b>
4.1	Supplemental Indenture dated as of June 15, 2016 from ComEd to BNY Mellon Trust Company of Illinois, as trustee, and D. G. Donovan, as co-trustee (File No. 001-01839, Form 8-K dated June 27, 2016, Exhibit 4.1)
10.1	Amendment No. 7 to Credit Agreement, dated as of March 23, 2011, among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated May 27, 2016, Exhibit 99.1)
10.2	Amendment No. 7 to Credit Agreement, dated as of March 23, 2011, among Exelon Generation Company, LLC, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 333-85496, Form 8-K dated May 27, 2016, Exhibit 99.2)
10.3	Amendment No. 4 to Credit Agreement, dated as of March 26, 2012, among Commonwealth Edison Company, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-01839, Form 8-K dated May 27, 2016, Exhibit 99.3)

**Table of Contents****Exhibit**

<b>No.</b>	<b>Description</b>
10.4	Amendment No. 6 to Credit Agreement, dated as of March 23, 2011, among PECO Energy Company, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 000-16844, Form 8-K dated May 27, 2016, Exhibit 99.4)
10.5	Amendment No. 5 to Credit Agreement, dated as of March 23, 2011, among Baltimore Gas and Electric Company, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-01910, Form 8-K dated May 27, 2016, Exhibit 99.5)
10.6	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of August 1, 2011, among Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, as Borrowers, the various financial institutions named therein, as Lenders, and Wells Fargo Bank, National Association, as Administrative Agent (File No. 001-31403, Form 8-K dated May 27, 2016, Exhibit 99.6)
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

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, 2016 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



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Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2016 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  
Christopher M. Crane  
President and Chief Executive Officer

(Principal Executive Officer) and Director

/s/ JONATHAN W. THAYER  
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 9, 2016

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  
Kenneth W. Cornew  
President and Chief Executive Officer

(Principal Executive Officer)

/s/ BRYAN P. WRIGHT  
Bryan P. Wright  
Senior Vice President and Chief Financial Officer

(Principal Financial Officer)

/s/ MATTHEW N. BAUER  
Matthew N. Bauer  
Vice President and Controller

(Principal Accounting Officer)

August 9, 2016

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  
Anne R. Pramaggiore

/s/ JOSEPH R. TRPIK, JR.  
Joseph R. Trpik, Jr.

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President and Chief Executive Officer

Senior Vice President, Chief Financial Officer and

(Principal Executive Officer)

Treasurer

(Principal Financial Officer)

/s/ GERALD J. KOZEL

Gerald J. Kozel

Vice President and Controller

(Principal Accounting Officer)

August 9, 2016

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Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**PECO ENERGY COMPANY**

/s/ CRAIG L. ADAMS  
Craig L. Adams  
President and Chief Executive Officer

(Principal Executive Officer)

/s/ SCOTT A. BAILEY  
Scott A. Bailey  
Vice President and Controller

(Principal Accounting Officer)

August 9, 2016

/s/ PHILLIP S. BARNETT  
Phillip S. Barnett  
Senior Vice President, Chief Financial Officer and

Treasurer

(Principal Financial Officer)

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.  
Calvin G. Butler, Jr.  
Chief Executive Officer

(Principal Executive Officer)

/s/ ANDREW W. HOLMES  
Andrew W. Holmes  
Vice President and Controller

(Principal Accounting Officer)

August 9, 2016

/s/ DAVID M. VAHOS  
David M. Vahos  
Senior Vice President, Chief Financial Officer and

Treasurer

(Principal Financial Officer)

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  
David M. Velazquez

/s/ DONNA J. KINZEL  
Donna J. Kinzel

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President and Chief Executive Officer

Senior Vice President, Chief Financial Officer and

(Principal Executive Officer)

Treasurer

(Principal Financial Officer)

/s/ ROBERT M. AIKEN

Robert M. Aiken

Vice President and Controller

(Principal Accounting Officer)

August 9, 2016



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Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**POTOMAC ELECTRIC POWER COMPANY**

/s/ DAVID M. VELAZQUEZ  
David M. Velazquez  
President and Chief Executive Officer  
(Principal Executive Officer)

/s/ DONNA J. KINZEL  
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 9, 2016

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  
David M. Velazquez  
President and Chief Executive Officer  
(Principal Executive Officer)

/s/ DONNA J. KINZEL  
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 9, 2016

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  
David M. Velazquez  
President and Chief Executive Officer  
(Principal Executive Officer)

/s/ DONNA J. KINZEL  
Donna J. Kinzel  
Senior Vice President, Chief Financial Officer and

Treasurer

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(Principal Financial Officer)

/s/ ROBERT M. AIKEN  
Robert M. Aiken  
Vice President and Controller  
(Principal Accounting Officer)

August 9, 2016