EXELON CORP
Form 10-Q
May 03, 2017
Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended March 31, 2017

or

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

Commission File Number	Name of Registrant; State or Other Jurisdiction of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 440 South LaSalle Street Chicago, Illinois 60605-1028	36-0938600

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

Table of Contents

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

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

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

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

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

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

The number of shares outstanding of each registrant s common stock as of March 31, 2017 was:

Exelon Corporation Common Stock, without par value	926,096,660
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,017,158
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

Table of Contents

TABLE OF CONTENTS

Table of Contents

Table of Contents

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities	
Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
Pepco Holdings or PHI	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
Pepco	Potomac Electric Power Company
Pepco Energy Services or PES	Pepco Energy Services, Inc. and its subsidiaries
PCI	Potomac Capital Investment Corporation and its subsidiaries
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
ACE Funding or ATF	Atlantic City Electric Transition Funding LLC
BSC	Exelon Business Services Company, LLC
PHISCO	PHI Service Company
Exelon Corporate	Exelon in its corporate capacity as a holding company
PHI Corporate	PHI in its corporate capacity as a holding company
Registrants	Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, collectively
Utility Registrants	ComEd, PECO, BGE, Pepco, DPL and ACE, collectively
AmerGen	AmerGen Energy Company, LLC
Antelope Valley	Antelope Valley Solar Ranch One
BondCo	RSB BondCo LLC
CENG	Constellation Energy Nuclear Group, LLC
ConEdison Solutions	The competitive retail electricity and natural gas business of Consolidated Edison Solutions, Inc., a subsidiary of Consolidated Edison, Inc.
Constellation	Constellation Energy Group, Inc.
EGTP	ExGen Texas Power, LLC
EGR	ExGen Renewables I, LLC
Entergy	Entergy Nuclear FitzPatrick LLC
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
FitzPatrick	James A. FitzPatrick nuclear generating station
Legacy PHI	PHI, Pepco, DPL and ACE, collectively
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
PETT	PECO Energy Transition Trust
RPG	Renewable Power Generation
SolGen	SolGen, LLC
UII	Unicom Investments, Inc.
Ventures	Exelon Ventures Company, LLC

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

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

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

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
EmPower Maryland	A Maryland demand-side management program for Pepco and DPL
EPA	United States Environmental Protection Agency
EPSA	Electric Power Supply Association
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
FASB	Financial Accounting Standards Board
FEJA	Illinois Public Act 99-0906 or Future Energy Jobs Act
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GAAP	Generally Accepted Accounting Principles in the United States
GCR	Gas Cost Rate
GHG	Greenhouse Gas
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
HSR Act	The Hart-Scott-Rodino Antitrust Improvements Act of 1976
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois Act	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
Integrys	Integrys Energy Services, Inc.
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ISO-NY	ISO New York
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LLRW	Low-Level Radioactive Waste
LT Plan	Long-term renewable resources procurement plan
LTIP	Long-Term Incentive Plan
MAPP	Mid-Atlantic Power Pathway
MATS	U.S. EPA Mercury and Air Toxics Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
Moody s	Moody s Investor Service
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value

GLOSSARY OF TERMS AND ABBREVIATIONS

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

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
RMC	Risk Management Committee
ROE	Return on equity
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RSSA	Reliability Support Services Agreement
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor s Ratings Services
SEC	United States Securities and Exchange Commission
Senate Bill 1	Maryland Senate Bill 1
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SGIG	Smart Grid Investment Grant from DOE
SILO	Sale-In, Lease-Out
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPFPA	Security, Police and Fire Professionals of America
SPP	Southwest Power Pool
Transition Bond Charge	Revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees
Transition Bonds	Transition Bonds issued by ACE Funding
UGSOA	United Government Security Officers of America
Upstream	Natural gas exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council
ZEC	Zero Emission Credit
ZES	Zero Emission Standard

8

Table of Contents

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 Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC (PHI), Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants) include those factors discussed herein, as well as the items discussed in (1) the Registrants combined 2016 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 24, Commitments and Contingencies; and (2) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

The public may read and copy any reports or other information that the Registrants file with the SEC at the SEC s public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services, the website maintained by the SEC at www.sec.gov and the Registrants websites at www.exeloncorp.com. Information contained on the Registrants websites shall not be deemed incorporated into, or to be a part of, this Report.

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Table of Contents

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended March 31,	
(In millions, except per share data)	**2017**	**2016**
Operating revenues		
Competitive businesses revenues	$ 4,560	$ 4,473
Rate-regulated utility revenues	4,197	3,100
Total operating revenues	8,757	7,573
Operating expenses		
Competitive businesses purchased power and fuel	2,795	2,440
Rate-regulated utility purchased power and fuel	1,104	814
Operating and maintenance	2,460	2,835
Depreciation and amortization	896	685
Taxes other than income	436	325
Total operating expenses	7,691	7,099
Gain on sales of assets	4	9
Bargain purchase gain	226	
Operating income	1,296	483
Other income and (deductions)		
Interest expense, net	(363)	(277)
Interest expense to affiliates	(10)	(10)
Other, net	283	114
Total other income and (deductions)	(90)	(173)
Income before income taxes	1,206	310
Income taxes	215	184
Equity in losses of unconsolidated affiliates	(10)	(3)
Net income	981	123
Net loss attributable to noncontrolling interests and preference stock dividends	(14)	(50)
Net income attributable to common shareholders	$ 995	$ 173
Comprehensive income, net of income taxes		
Net income	$ 981	$ 123
Other comprehensive income (loss), net of income taxes		
Pension and non-pension postretirement benefit plans:		
Prior service benefit reclassified to periodic benefit cost	(13)	(12)
Actuarial loss reclassified to periodic benefit cost	49	46
Pension and non-pension postretirement benefit plan valuation adjustment	(59)	(1)
Unrealized gain (loss) on cash flow hedges	6	(7)

Unrealized gain (loss) on equity investments	3	(3)
Unrealized gain on foreign currency translation	1	6
Unrealized gain (loss) on marketable securities	1	(1)
Other comprehensive (loss) income	(12)	28
Comprehensive income	969	151
Comprehensive loss attributable to noncontrolling interests and preference stock dividends	(16)	(50)
Comprehensive income attributable to common shareholders	$ 985	$ 201
Average shares of common stock outstanding:		
Basic	928	923
Diluted	930	925
Earnings per average common share:		
Basic	$ 1.07	$ 0.19
Diluted	$ 1.07	$ 0.19
Dividends declared per common share	$ 0.33	$ 0.31

See the Combined Notes to Consolidated Financial Statements

Table of Contents

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended March 31,	
(In millions)	**2017**	**2016**
Cash flows from operating activities		
Net income	$ 981	$ 123
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	1,274	1,063
Impairment of long-lived assets	10	119
Gain on sales of assets	(4)	(9)
Bargain purchase gain	(226)	
Deferred income taxes and amortization of investment tax credits	189	127
Net fair value changes related to derivatives	47	(107)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(175)	(55)
Other non-cash operating activities	118	804
Changes in assets and liabilities:		
Accounts receivable	313	117
Inventories	109	142
Accounts payable and accrued expenses	(623)	(571)
Option premiums (paid) received, net	(6)	17
Collateral (posted) received, net	(110)	206
Income taxes	50	47
Pension and non-pension postretirement benefit contributions	(307)	(239)
Other assets and liabilities	(439)	(311)
Net cash flows provided by operating activities	1,201	1,473
Cash flows from investing activities		
Capital expenditures	(2,114)	(2,202)
Proceeds from nuclear decommissioning trust fund sales	1,767	2,240
Investment in nuclear decommissioning trust funds	(1,833)	(2,297)
Acquisition of businesses, net	(212)	(6,645)
Proceeds from termination of direct financing lease investment		360
Change in restricted cash	(1)	(2)
Other investing activities	(18)	(2)
Net cash flows used in investing activities	(2,411)	(8,548)
Cash flows from financing activities		
Changes in short-term borrowings	721	1,647
Proceeds from short-term borrowings with maturities greater than 90 days	560	123
Repayments on short-term borrowings with maturities greater than 90 days	(500)	
Issuance of long-term debt	763	151
Retirement of long-term debt	(65)	(116)
Dividends paid on common stock	(303)	(287)
Proceeds from employee stock plans	12	9
Other financing activities	(4)	6
Net cash flows provided by financing activities	1,184	1,533

Decrease in cash and cash equivalents	(26)	(5,542)
Cash and cash equivalents at beginning of period	635	6,502
Cash and cash equivalents at end of period	$ 609	$ 960

See the Combined Notes to Consolidated Financial Statements

Table of Contents

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	March 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 609	$ 635
Restricted cash and cash equivalents	254	253
Deposit with IRS	1,250	1,250
Accounts receivable, net		
Customer	3,886	4,158
Other	1,133	1,201
Mark-to-market derivative assets	847	917
Unamortized energy contract assets	103	88
Inventories, net		
Fossil fuel and emission allowances	249	364
Materials and supplies	1,312	1,274
Regulatory assets	1,330	1,342
Other	1,221	930
Total current assets	12,194	12,412
Property, plant and equipment, net	72,630	71,555
Deferred debits and other assets		
Regulatory assets	10,051	10,046
Nuclear decommissioning trust funds	12,362	11,061
Investments	648	629
Goodwill	6,677	6,677
Mark-to-market derivative assets	539	492
Unamortized energy contract assets	432	447
Pledged assets for Zion Station decommissioning	95	113
Other	1,440	1,472
Total deferred debits and other assets	32,244	30,937
Total assets[(a)]	$ 117,068	$ 114,904

See the Combined Notes to Consolidated Financial Statements

Table of Contents

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	March 31, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 2,048	$ 1,267
Long-term debt due within one year	3,645	2,430
Accounts payable	3,011	3,441
Accrued expenses	3,007	3,460
Payables to affiliates	8	8
Regulatory liabilities	637	602
Mark-to-market derivative liabilities	228	282
Unamortized energy contract liabilities	388	407
Renewable energy credit obligation	400	428
PHI merger related obligation	123	151
Other	942	981
Total current liabilities	14,437	13,457
Long-term debt	31,044	31,575
Long-term debt to financing trusts	641	641
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	18,518	18,138
Asset retirement obligations	9,634	9,111
Pension obligations	4,082	4,248
Non-pension postretirement benefit obligations	1,928	1,848
Spent nuclear fuel obligation	1,136	1,024
Regulatory liabilities	4,302	4,187
Mark-to-market derivative liabilities	420	392
Unamortized energy contract liabilities	779	830
Payable for Zion Station decommissioning	3	14
Other	1,853	1,827
Total deferred credits and other liabilities	42,655	41,619
Total liabilities[a]	88,777	87,292
Commitments and contingencies		
Shareholders equity		
Common stock (No par value, 2000 shares authorized, 926 shares and 924 shares outstanding at March 31, 2017 and December 31, 2016, respectively)	18,807	18,794
Treasury stock, at cost (35 shares at March 31, 2017 and December 31, 2016, respectively)	(2,327)	(2,327)
Retained earnings	12,720	12,030
Accumulated other comprehensive loss, net	(2,670)	(2,660)
Total shareholders equity	26,530	25,837
Noncontrolling interests	1,761	1,775
Total equity	28,291	27,612

Total liabilities and shareholders equity	$ 117,068	$ 114,904

(a) Exelon s consolidated assets include $9,148 million and $8,893 million at March 31, 2017 and December 31, 2016, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon s consolidated liabilities include $3,345 million and $3,356 million at March 31, 2017 and December 31, 2016, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 3 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Shareholders Equity
Balance, December 31, 2016	958,778	$ 18,794	$ (2,327)	$ 12,030	$ (2,660)	$ 1,775	$ 27,612
Net income (loss)				995		(14)	981
Long-term incentive plan activity	1,739	1					1
Employee stock purchase plan issuances	323	12					12
Changes in equity of noncontrolling interests						2	2
Common stock dividends				(305)			(305)
Other comprehensive loss, net of income taxes					(10)	(2)	(12)
Balance at March 31, 2017	960,840	$ 18,807	$ (2,327)	$ 12,720	$ (2,670)	$ 1,761	$ 28,291

See the Combined Notes to Consolidated Financial Statements

15

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended March 31, 2017	2016
Operating revenues		
Operating revenues	$ 4,558	$ 4,471
Operating revenues from affiliates	330	268
Total operating revenues	4,888	4,739
Operating expenses		
Purchased power and fuel	2,796	2,440
Purchased power and fuel from affiliates	2	2
Operating and maintenance	1,309	1,296
Operating and maintenance from affiliates	179	171
Depreciation and amortization	302	289
Taxes other than income	143	126
Total operating expenses	4,731	4,324
Gain on sales of assets	4	
Bargain purchase gain	226	
Operating income	387	415
Other income and (deductions)		
Interest expense, net	(90)	(87)
Interest expense to affiliates	(10)	(10)
Other, net	259	93
Total other income and (deductions)	159	(4)
Income before income taxes	546	411
Income taxes	127	151
Equity in losses of unconsolidated affiliates	(10)	(3)
Net income	409	257
Net loss attributable to noncontrolling interests	(14)	(53)
Net income attributable to membership interest	$ 423	$ 310
Comprehensive income, net of income taxes		
Net income	$ 409	$ 257
Other comprehensive income (loss), net of income taxes		
Unrealized gain (loss) on cash flow hedges	6	(5)
Unrealized gain (loss) on equity investments	4	(2)
Unrealized gain on foreign currency translation	1	6

Other comprehensive income (loss)	11	(1)
Comprehensive income	420	256
Comprehensive loss attributable to noncontrolling interests	(16)	(53)
Comprehensive income attributable to membership interest	$ 436	$ 309

See the Combined Notes to Consolidated Financial Statements

16

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Three Months Ended March 31, 2017	2016
Cash flows from operating activities		
Net income	$ 409	$ 257
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	678	667
Impairment of long-lived assets	10	119
Gain on sales of assets	(4)	
Bargain purchase gain	(226)	
Deferred income taxes and amortization of investment tax credits	112	68
Net fair value changes related to derivatives	51	(106)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(175)	(55)
Other non-cash operating activities	(10)	51
Changes in assets and liabilities:		
Accounts receivable	195	173
Receivables from and payables to affiliates, net	23	(17)
Inventories	81	93
Accounts payable and accrued expenses	62	(363)
Option premiums (paid) received, net	(6)	17
Collateral (posted) received, net	(102)	198
Income taxes	(81)	(60)
Pension and non-pension postretirement benefit contributions	(110)	(112)
Other assets and liabilities	(167)	(148)
Net cash flows provided by operating activities	740	782
Cash flows from investing activities		
Capital expenditures	(923)	(1,125)
Proceeds from nuclear decommissioning trust fund sales	1,767	2,240
Investment in nuclear decommissioning trust funds	(1,833)	(2,297)
Acquisition of businesses, net	(212)	(1)
Change in restricted cash	18	4
Other investing activities	(29)	(25)
Net cash flows used in investing activities	(1,212)	(1,204)
Cash flows from financing activities		
Changes in short-term borrowings	(42)	1,377
Proceeds from short-term borrowings with maturities greater than 90 days	60	123
Issuance of long-term debt	762	151
Retirement of long-term debt	(30)	(94)
Changes in Exelon intercompany money pool	(1)	(1,183)
Distribution to member	(164)	(55)
Contribution from member		44
Other financing activities	(3)	5
Net cash flows provided by financing activities	582	368

Increase (Decrease) in cash and cash equivalents	110	(54)
Cash and cash equivalents at beginning of period	290	431
Cash and cash equivalents at end of period	$ 400	$ 377

See the Combined Notes to Consolidated Financial Statements

17

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	March 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 400	$ 290
Restricted cash and cash equivalents	140	158
Accounts receivable, net		
Customer	2,278	2,433
Other	545	558
Mark-to-market derivative assets	847	917
Receivables from affiliates	141	156
Unamortized energy contract assets	103	88
Inventories, net		
Fossil fuel and emission allowances	222	292
Materials and supplies	957	935
Other	881	701
Total current assets	6,514	6,528
Property, plant and equipment, net	25,893	25,585
Deferred debits and other assets		
Nuclear decommissioning trust funds	12,362	11,061
Investments	435	418
Goodwill	47	47
Mark-to-market derivative assets	527	476
Prepaid pension asset	1,646	1,595
Pledged assets for Zion Station decommissioning	95	113
Unamortized energy contract assets	432	447
Deferred income taxes	10	16
Other	648	688
Total deferred debits and other assets	16,202	14,861
Total assets[a]	$ 48,609	$ 46,974

See the Combined Notes to Consolidated Financial Statements

18

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	March 31, 2017	December 31, 2016
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 717	$ 699
Long-term debt due within one year	1,156	1,117
Accounts payable	1,482	1,610
Accrued expenses	720	989
Payables to affiliates	145	137
Borrowings from Exelon intercompany money pool	54	55
Mark-to-market derivative liabilities	209	263
Unamortized energy contract liabilities	68	72
Renewable energy credit obligation	400	428
Other	286	313
Total current liabilities	5,237	5,683
Long-term debt	7,904	7,202
Long-term debt to affiliate	919	922
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,850	5,585
Asset retirement obligations	9,444	8,922
Non-pension postretirement benefit obligations	926	930
Spent nuclear fuel obligation	1,136	1,024
Payables to affiliates	2,776	2,608
Mark-to-market derivative liabilities	157	153
Unamortized energy contract liabilities	78	80
Payable for Zion Station decommissioning	3	14
Other	615	595
Total deferred credits and other liabilities	20,985	19,911
Total liabilities[(a)]	35,045	33,718
Commitments and contingencies		
Equity		
Member s equity		
Membership interest	9,310	9,261
Undistributed earnings	2,534	2,275
Accumulated other comprehensive loss, net	(41)	(54)
Total member s equity	11,803	11,482
Noncontrolling interests	1,761	1,774
Total equity	13,564	13,256
Total liabilities and equity	**$ 48,609**	**$ 46,974**

(a) Generation s consolidated assets include $9,059 million and $8,817 million at March 31, 2017 and December 31, 2016, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation s consolidated liabilities include $3,174 million and $3,170 million at March 31, 2017 and December 31, 2016, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 3 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(Unaudited)

	Member s Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2016	$ 9,261	$ 2,275	$ (54)	$ 1,774	$ 13,256
Net income (loss)		423		(14)	409
Changes in equity of noncontrolling interests				3	3
Distribution of net retirement benefit obligation to member	49				49
Distribution to member		(164)			(164)
Other comprehensive income (loss), net of income taxes			13	(2)	11
Balance, March 31, 2017	$ 9,310	$ 2,534	$ (41)	$ 1,761	$ 13,564

See the Combined Notes to Consolidated Financial Statements

20

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended March 31, 2017	2016
Operating revenues		
Electric operating revenues	$ 1,293	$ 1,244
Operating revenues from affiliates	5	5
Total operating revenues	1,298	1,249
Operating expenses		
Purchased power	329	343
Purchased power from affiliate	5	5
Operating and maintenance	307	305
Operating and maintenance from affiliate	63	63
Depreciation and amortization	208	189
Taxes other than income	72	75
Total operating expenses	984	980
Gain on sale of assets		5
Operating income	314	274
Other income and (deductions)		
Interest expense, net	(82)	(83)
Interest expense to affiliates	(3)	(3)
Other, net	4	4
Total other income and (deductions)	(81)	(82)
Income before income taxes	233	192
Income taxes	92	77
Net income	$ 141	$ 115
Comprehensive income	$ 141	$ 115

See the Combined Notes to Consolidated Financial Statements

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended March 31,	
(In millions)	**2017**	**2016**
Cash flows from operating activities		
Net income	$ 141	$ 115
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	208	189
Deferred income taxes and amortization of investment tax credits	137	70
Other non-cash operating activities	31	32
Changes in assets and liabilities:		
Accounts receivable	92	69
Receivables from and payables to affiliates, net	(16)	
Inventories	4	7
Accounts payable and accrued expenses	(327)	(207)
Collateral (posted) received, net	(7)	7
Income taxes	(34)	20
Pension and non-pension postretirement benefit contributions	(35)	(32)
Other assets and liabilities	(49)	14
Net cash flows provided by operating activities	145	284
Cash flows from investing activities		
Capital expenditures	(535)	(639)
Change in restricted cash	(1)	
Other investing activities	7	13
Net cash flows used in investing activities	(529)	(626)
Cash flows from financing activities		
Changes in short-term borrowings	365	349
Contributions from parent	100	39
Dividends paid on common stock	(105)	(91)
Other financing activities	(1)	(1)
Net cash flows provided by financing activities	359	296
Decrease in cash and cash equivalents	(25)	(46)
Cash and cash equivalents at beginning of period	56	67
Cash and cash equivalents at end of period	$ 31	$ 21

See the Combined Notes to Consolidated Financial Statements

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	March 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 31	$ 56
Restricted cash	3	2
Accounts receivable, net		
Customer	461	528
Other	199	218
Receivables from affiliates	360	356
Inventories, net	154	159
Regulatory assets	183	190
Other	55	45
Total current assets	1,446	1,554
Property, plant and equipment, net	19,692	19,335
Deferred debits and other assets		
Regulatory assets	1,032	977
Investments	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,294	2,170
Prepaid pension asset	1,330	1,343
Other	331	325
Total deferred debits and other assets	7,618	7,446
Total assets	$ 28,756	$ 28,335

See the Combined Notes to Consolidated Financial Statements

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	March 31, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 365	$
Long-term debt due within one year	1,125	425
Accounts payable	518	645
Accrued expenses	1,061	1,250
Payables to affiliates	52	65
Customer deposits	117	121
Regulatory liabilities	311	329
Mark-to-market derivative liability	19	19
Other	77	84
Total current liabilities	3,645	2,938
Long-term debt	5,910	6,608
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,502	5,364
Asset retirement obligations	121	119
Non-pension postretirement benefits obligations	234	239
Regulatory liabilities	3,492	3,369
Mark-to-market derivative liability	263	239
Other	523	529
Total deferred credits and other liabilities	10,135	9,859
Total liabilities	19,895	19,610
Commitments and contingencies		
Shareholders equity		
Common stock	1,588	1,588
Other paid-in capital	6,250	6,150
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	2,662	2,626
Total shareholders equity	8,861	8,725
Total liabilities and shareholders equity	$ 28,756	$ 28,335

See the Combined Notes to Consolidated Financial Statements

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders Equity
Balance, December 31, 2016	$ 1,588	$ 6,150	$ (1,639)	$ 2,626	$ 8,725
Net income			141		141
Appropriation of retained earnings for future dividends			(141)	141	
Common stock dividends				(105)	(105)
Contribution from parent		100			100
Balance, March 31, 2017	$ 1,588	$ 6,250	$ (1,639)	$ 2,662	$ 8,861

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)

	Three Months Ended March 31,	
(In millions)	**2017**	**2016**
Operating revenues		
Electric operating revenues	$ 589	$ 643
Natural gas operating revenues	206	197
Operating revenues from affiliates	1	1
Total operating revenues	796	841
Operating expenses		
Purchased power	156	166
Purchased fuel	86	77
Purchased power from affiliate	45	78
Operating and maintenance	174	177
Operating and maintenance from affiliates	34	38
Depreciation and amortization	71	67
Taxes other than income	38	42
Total operating expenses	604	645
Operating income	192	196
Other income and (deductions)		
Interest expense, net	(28)	(28)
Interest expense to affiliates	(3)	(3)
Other, net	2	2
Total other income and (deductions)	(29)	(29)
Income before income taxes	163	167
Income taxes	36	43
Net income	$ 127	$ 124
Comprehensive income	$ 127	$ 124

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Three Months Ended March 31, 2017	2016
Cash flows from operating activities		
Net income	$ 127	$ 124
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	71	67
Deferred income taxes and amortization of investment tax credits	24	23
Other non-cash operating activities	23	24
Changes in assets and liabilities:		
Accounts receivable	(25)	(51)
Receivables from and payables to affiliates, net	(10)	4
Inventories	19	24
Accounts payable and accrued expenses	(82)	18
Income taxes	25	29
Pension and non-pension postretirement benefit contributions	(23)	(29)
Other assets and liabilities	(85)	(95)
Net cash flows provided by operating activities	64	138
Cash flows from investing activities		
Capital expenditures	(159)	(195)
Changes in Exelon intercompany money pool	131	(160)
Other investing activities	1	4
Net cash flows used in investing activities	(27)	(351)
Cash flows from financing activities		
Dividends paid on common stock	(72)	(69)
Net cash flows used in financing activities	(72)	(69)
Decrease in cash and cash equivalents	(35)	(282)
Cash and cash equivalents at beginning of period	63	295
Cash and cash equivalents at end of period	$ 28	$ 13

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	March 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 28	$ 63
Restricted cash and cash equivalents	4	4
Accounts receivable, net		
Customer	314	306
Other	122	131
Receivables from affiliates	6	4
Receivable from Exelon intercompany pool		131
Inventories, net		
Fossil fuel	14	35
Materials and supplies	29	27
Prepaid utility taxes	100	9
Regulatory assets	40	29
Other	21	18
Total current assets	678	757
Property, plant and equipment, net	7,659	7,565
Deferred debits and other assets		
Regulatory assets	1,708	1,681
Investments	25	25
Receivable from affiliates	482	438
Prepaid pension asset	361	345
Other	19	20
Total deferred debits and other assets	2,595	2,509
Total assets	$ 10,932	$ 10,831

See the Combined Notes to Consolidated Financial Statements

28

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	March 31, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Long-term debt due within one year	$ 500	$
Accounts payable	288	342
Accrued expenses	92	104
Payables to affiliates	55	63
Customer deposits	62	61
Regulatory liabilities	161	127
Other	29	30
Total current liabilities	1,187	727
Long-term debt	2,080	2,580
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,076	3,006
Asset retirement obligations	28	28
Non-pension postretirement benefits obligations	289	289
Regulatory liabilities	530	517
Other	88	85
Total deferred credits and other liabilities	4,011	3,925
Total liabilities	7,462	7,416
Commitments and contingencies		
Shareholder s equity		
Common stock	2,473	2,473
Retained earnings	996	941
Accumulated other comprehensive income, net	1	1
Total shareholder s equity	3,470	3,415
Total liabilities and shareholder s equity	$ 10,932	$ 10,831

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDER S EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	Total Shareholder s Equity
Balance, December 31, 2016	$ 2,473	$ 941	$ 1	$ 3,415
Net income		127		127
Common stock dividends		(72)		(72)
Balance, March 31, 2017	$ 2,473	$ 996	$ 1	$ 3,470

See the Combined Notes to Consolidated Financial Statements

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended March 31, 2017	2016
Operating revenues		
Electric operating revenues	$ 665	$ 678
Natural gas operating revenues	281	246
Operating revenues from affiliates	5	5
Total operating revenues	951	929
Operating expenses		
Purchased power	133	127
Purchased fuel	83	75
Purchased power from affiliate	134	171
Operating and maintenance	148	168
Operating and maintenance from affiliates	35	34
Depreciation and amortization	128	109
Taxes other than income	62	58
Total operating expenses	723	742
Operating income	228	187
Other income and (deductions)		
Interest expense, net	(23)	(20)
Interest expense to affiliates	(4)	(4)
Other, net	4	4
Total other income and (deductions)	(23)	(20)
Income before income taxes	205	167
Income taxes	80	66
Net income	125	101
Preference stock dividends		3
Net income attributable to common shareholder	$ 125	$ 98
Comprehensive income	$ 125	$ 101
Comprehensive income attributable to preference stock dividends		3
Comprehensive income attributable to common shareholder	$ 125	$ 98

See the Combined Notes to Consolidated Financial Statements

31

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Three Months Ended March 31, 2017	2016
Cash flows from operating activities		
Net income	$ 125	$ 101
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	128	109
Deferred income taxes and amortization of investment tax credits	72	26
Other non-cash operating activities	24	44
Changes in assets and liabilities:		
Accounts receivable	(7)	(44)
Receivables from and payables to affiliates, net	(7)	7
Inventories	17	17
Accounts payable and accrued expenses	(121)	3
Income taxes	33	78
Pension and non-pension postretirement benefit contributions	(44)	(38)
Other assets and liabilities	(52)	(30)
Net cash flows provided by operating activities	168	273
Cash flows from investing activities		
Capital expenditures	(166)	(176)
Change in restricted cash	(19)	(20)
Other investing activities	4	5
Net cash flows used in investing activities	(181)	(191)
Cash flows from financing activities		
Changes in short-term borrowings	50	(60)
Dividends paid on preference stock		(3)
Dividends paid on common stock	(49)	(45)
Contributions from parent		21
Other financing activities		1
Net cash flows provided by (used in) financing activities	1	(86)
Decrease in cash and cash equivalents	(12)	(4)
Cash and cash equivalents at beginning of period	23	9
Cash and cash equivalents at end of period	$ 11	$ 5

See the Combined Notes to Consolidated Financial Statements

32

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	March 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 11	$ 23
Restricted cash and cash equivalents	43	24
Accounts receivable, net		
Customer	393	395
Other	79	102
Receivables from affiliates	1	
Inventories, net		
Gas held in storage	10	30
Materials and supplies	41	38
Prepaid utility taxes	32	15
Regulatory assets	191	208
Other	11	7
Total current assets	812	842
Property, plant and equipment, net	7,166	7,040
Deferred debits and other assets		
Regulatory assets	499	504
Investments	12	12
Prepaid pension asset	322	297
Other	10	9
Total deferred debits and other assets	843	822
Total assets[(a)]	$ 8,821	$ 8,704

See the Combined Notes to Consolidated Financial Statements

33

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	March 31, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 95	$ 45
Long-term debt due within one year	41	41
Accounts payable	186	205
Accrued expenses	120	175
Payables to affiliates	49	55
Customer deposits	112	110
Regulatory liabilities	67	50
Other	23	26
Total current liabilities	693	707
Long-term debt	2,282	2,281
Long-term debt to financing trust	252	252
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,295	2,219
Asset retirement obligations	20	21
Non-pension postretirement benefits obligations	202	205
Regulatory liabilities	94	110
Other	59	61
Total deferred credits and other liabilities	2,670	2,616
Total liabilities[a]	5,897	5,856
Commitments and contingencies		
Shareholders equity		
Common stock	1,421	1,421
Retained earnings	1,503	1,427
Total shareholders equity	2,924	2,848
Total liabilities and shareholders equity	$ 8,821	$ 8,704

(a) BGE s consolidated assets include $45 million and $26 million at March 31, 2017 and December 31, 2016, respectively, of BGE s consolidated VIE that can only be used to settle the liabilities of the VIE. BGE s consolidated liabilities include $42 million and $42 million at March 31, 2017 and December 31, 2016, respectively, of BGE s consolidated VIE for which the VIE creditors do not have recourse to BGE. See Note 3 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholders Equity
Balance, December 31, 2016	$ 1,421	$ 1,427	$ 2,848
Net income		125	125
Common stock dividends		(49)	(49)
Balance, March 31, 2017	$ 1,421	$ 1,503	$ 2,924

See the Combined Notes to Consolidated Financial Statements

35

Table of Contents

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

	Successor		*Predecessor*
(In millions)	**Three Months Ended March 31, 2017**	**March 24 to March 31, 2016**	**January 1 to March 23, 2016**
Operating revenues			
Electric operating revenues	$ 1,097	$ 90	$ 1,096
Natural gas operating revenues	66	3	57
Operating revenues from affiliates	12	12	
Total operating revenues	1,175	105	1,153
Operating expenses			
Purchased power	288	26	471
Purchased fuel	29	1	26
Purchased power and fuel from affiliates	144	11	
Operating and maintenance	223	447	294
Operating and maintenance from affiliates	33	2	
Depreciation and amortization	167	14	152
Taxes other than income	111	15	105
Total operating expenses	995	516	1,048
Operating income (loss)	180	(411)	105
Other income and (deductions)			
Interest expense, net	(62)	(6)	(65)
Other, net	13	2	(4)
Total other income and (deductions)	(49)	(4)	(69)
Income (loss) before income taxes	131	(415)	36
Income taxes	(9)	(106)	17
Net income (loss)	$ 140	$ (309)	$ 19
Comprehensive income (loss), net of income taxes			
Net income (loss)	$ 140	$ (309)	$ 19
Other comprehensive income, net of income taxes			
Pension and non-pension postretirement benefit plans:			
Actuarial loss reclassified to periodic cost			1
Other comprehensive income			1
Comprehensive income (loss)	$ 140	$ (309)	$ 20

See the Combined Notes to Consolidated Financial Statements

36

Table of Contents

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	*Successor* Three Months Ended March 31, 2017	March 24 to March 31, 2016	*Predecessor* January 1 to March 23, 2016
Cash flows from operating activities			
Net income (loss)	$ 140	$ (309)	$ 19
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:			
Depreciation and amortization	167	14	152
Deferred income taxes and amortization of investment tax credits	13	(112)	19
Net fair value changes related to derivatives			18
Other non-cash operating activities	(8)	410	46
Changes in assets and liabilities:			
Accounts receivable	68	16	(28)
Receivables from and payables to affiliates, net	(8)		
Inventories	(11)		(4)
Accounts payable and accrued expenses	(81)	(4)	42
Income taxes	55	7	12
Pension and non-pension postretirement benefit contributions	(66)		(4)
Other assets and liabilities	(75)	(25)	(8)
Net cash flows provided by (used in) operating activities	194	(3)	264
Cash flows from investing activities			
Capital expenditures	(320)	(29)	(273)
Changes in restricted cash	2	(1)	3
Purchases of investments		(2)	(68)
Other investing activities	(3)	2	(5)
Net cash flows used in investing activities	(321)	(30)	(343)
Cash flows from financing activities			
Changes in short-term borrowings	145	(20)	(121)
Proceeds from short-term borrowings with maturities greater than 90 days			500
Repayments of short-term borrowings with maturities greater than 90 days	(500)		
Issuance of long-term debt	1		
Retirement of long-term debt	(24)		(11)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan and employee-related compensation			2
Distribution to member	(69)	(108)	
Contribution from member	500		
Change in Exelon intercompany money pool	13	(7)	
Other financing activities			2
Net cash flows provided by (used in) financing activities	66	(135)	372
(Decrease) Increase in cash and cash equivalents	(61)	(168)	293
Cash and cash equivalents at beginning of period	170	319	26

Cash and cash equivalents at end of period	$ 109	$ 151	$ 319

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	Successor	
(In millions)	**March 31, 2017**	**December 31, 2016**
ASSETS		
Current assets		
Cash and cash equivalents	$ 109	$ 170
Restricted cash and cash equivalents	41	43
Accounts receivable, net		
Customer	440	496
Other	210	283
Inventories, net		
Gas held in storage	2	6
Materials and supplies	131	116
Regulatory assets	653	653
Other	64	71
Total current assets	1,650	1,838
Property, plant and equipment, net	11,801	11,598
Deferred debits and other assets		
Regulatory assets	2,791	2,851
Investments	133	133
Goodwill	4,005	4,005
Long-term note receivable	4	4
Prepaid pension asset	549	509
Deferred income taxes	5	6
Other	80	81
Total deferred debits and other assets	7,567	7,589
Total assets[(a)]	$ 21,018	$ 21,025

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	Successor	
(In millions)	**March 31, 2017**	**December 31, 2016**
LIABILITIES AND MEMBER S EQUITY		
Current liabilities		
Short-term borrowings	$ 167	$ 522
Long-term debt due within one year	241	253
Accounts payable	386	458
Accrued expenses	269	272
Payables to affiliates	84	94
Unamortized energy contract liabilities	320	335
Borrowings from Exelon intercompany money pool	13	
Customer deposits	121	123
Merger related obligation	74	101
Regulatory liabilities	82	79
Other	43	47
Total current liabilities	1,800	2,284
Long-term debt	5,619	5,645
Deferred credits and other liabilities		
Regulatory liabilities	154	158
Deferred income taxes and unamortized investment tax credits	3,789	3,775
Asset retirement obligations	14	14
Non-pension postretirement benefit obligations	129	134
Unamortized energy contract liabilities	701	750
Other	225	249
Total deferred credits and other liabilities	5,012	5,080
Total liabilities[(a)]	12,431	13,009
Commitments and contingencies		
Member s equity		
Membership interest	8,577	8,077
Undistributed earnings (losses)	10	(61)
Total member s equity	8,587	8,016
Total liabilities and member s equity	$ 21,018	$ 21,025

(a) PHI s consolidated total assets include $44 million and $49 million at March 31, 2017 and December 31, 2016, respectively, of PHI s consolidated VIE that can only be used to settle the liabilities of the VIE. PHI s consolidated total liabilities include $129 million and $143 million at March 31, 2017 and December 31, 2016, respectively, of PHI s consolidated VIE for which the VIE creditors do not have recourse to PHI. See Note 3 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(Unaudited)

(In millions)	Membership Interest	Undistributed Earnings (Losses)	Member s Equity
Successor			
Balance, December 31, 2016	$ 8,077	$ (61)	$ 8,016
Net income		140	140
Distribution to member		(69)	(69)
Contribution from member	500		500
Balance, March 31, 2017	$ 8,577	$ 10	$ 8,587

See the Combined Notes to Consolidated Financial Statements

40

Table of Contents

POTOMAC ELECTRIC POWER COMPANY

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended March 31, 2017	2016
Operating revenues		
Electric operating revenues	$ 529	$ 550
Operating revenues from affiliates	1	1
Total operating revenues	530	551
Operating expenses		
Purchased power	83	191
Purchased power from affiliates	83	6
Operating and maintenance	101	288
Operating and maintenance from affiliates	12	2
Depreciation and amortization	82	75
Taxes other than income	90	94
Total operating expenses	451	656
Operating income (loss)	79	(105)
Other income and (deductions)		
Interest expense, net	(29)	(37)
Other, net	8	9
Total other income and (deductions)	(21)	(28)
Income (loss) before income taxes	58	(133)
Income taxes		(25)
Net income (loss)	$ 58	$ (108)
Comprehensive income (loss)	$ 58	$ (108)

See the Combined Notes to Consolidated Financial Statements

41

Table of Contents

POTOMAC ELECTRIC POWER COMPANY

STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Three Months Ended March 31, 2017	2016
Cash flows from operating activities		
Net income (loss)	$ 58	$ (108)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation and amortization	82	75
Deferred income taxes and amortization of investment tax credits	5	(31)
Other non-cash operating activities	(15)	153
Changes in assets and liabilities:		
Accounts receivable	45	(24)
Receivables from and payables to affiliates, net	(6)	55
Inventories	(10)	1
Accounts payable and accrued expenses	(49)	(4)
Income taxes	20	151
Pension and non-pension postretirement benefit contributions	(64)	(1)
Other assets and liabilities	(37)	(9)
Net cash flows provided by operating activities	29	258
Cash flows from investing activities		
Capital expenditures	(139)	(109)
Purchases of investments		(31)
Changes in restricted cash		2
Other investing activities	(5)	2
Net cash flows used in investing activities	(144)	(136)
Cash flows from financing activities		
Changes in short-term borrowings	144	(64)
Issuance of long-term debt	1	
Dividends paid on common stock	(30)	(39)
Other financing activities	(1)	
Net cash flows provided by (used in) financing activities	114	(103)
(Decrease) Increase in cash and cash equivalents	(1)	19
Cash and cash equivalents at beginning of period	9	5
Cash and cash equivalents at end of period	$ 8	$ 24

See the Combined Notes to Consolidated Financial Statements

Table of Contents

POTOMAC ELECTRIC POWER COMPANY

BALANCE SHEETS

(Unaudited)

(In millions)	March 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 8	$ 9
Restricted cash and cash equivalents	33	33
Accounts receivable, net		
Customer	199	235
Other	127	150
Inventories, net	73	63
Regulatory assets	173	162
Other	21	32
Total current assets	634	684
Property, plant and equipment, net	5,659	5,571
Deferred debits and other assets		
Regulatory assets	679	690
Investments	101	102
Prepaid pension asset	337	282
Other	7	6
Total deferred debits and other assets	1,124	1,080
Total assets	$ 7,417	$ 7,335

See the Combined Notes to Consolidated Financial Statements

Table of Contents

POTOMAC ELECTRIC POWER COMPANY

BALANCE SHEETS

(Unaudited)

(In millions)	March 31, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Short-term borrowings	$ 167	$ 23
Long-term debt due within one year	17	16
Accounts payable	141	209
Accrued expenses	125	113
Payables to affiliates	68	74
Customer deposits	53	53
Regulatory liabilities	10	11
Merger related obligation	47	68
Other	23	29
Total current liabilities	651	596
Long-term debt	2,333	2,333
Deferred credits and other liabilities		
Regulatory liabilities	19	20
Deferred income taxes and unamortized investment tax credits	1,913	1,910
Non-pension postretirement benefit obligations	41	43
Other	132	133
Total deferred credits and other liabilities	2,105	2,106
Total liabilities	5,089	5,035
Commitments and contingencies		
Shareholder s equity		
Common stock	1,309	1,309
Retained earnings	1,019	991
Total shareholder s equity	2,328	2,300
Total liabilities and shareholder s equity	$ 7,417	$ 7,335

See the Combined Notes to Consolidated Financial Statements

44

Table of Contents

POTOMAC ELECTRIC POWER COMPANY

STATEMENT OF CHANGES IN SHAREHOLDER S EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholder s Equity
Balance, December 31, 2016	$ 1,309	$ 991	$ 2,300
Net income		58	58
Common stock dividends		(30)	(30)
Balance, March 31, 2017	$ 1,309	$ 1,019	$ 2,328

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 March 31, 2017**	**2016**
Operating revenues		
Electric operating revenues	$ 294	$ 301
Natural gas operating revenues	66	59
Operating revenues from affiliates	2	2
Total operating revenues	362	362
Operating expenses		
Purchased power	77	147
Purchased fuel	29	25
Purchased power from affiliate	51	4
Operating and maintenance	66	204
Operating and maintenance from affiliates	7	
Depreciation and amortization	39	39
Taxes other than income	15	15
Total operating expenses	284	434
Operating income (loss)	78	(72)
Other income and (deductions)		
Interest expense, net	(13)	(12)
Other, net	3	3
Total other income and (deductions)	(10)	(9)
Income (loss) before income taxes	68	(81)
Income taxes	11	(9)
Net income (loss)	$ 57	$ (72)
Comprehensive income (loss)	$ 57	$ (72)

See the Combined Notes to Consolidated Financial Statements

Table of Contents

DELMARVA POWER & LIGHT COMPANY

STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	**Three Months Ended March 31, 2017**	**2016**
Cash flows from operating activities		
Net income (loss)	$ 57	$ (72)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation and amortization	39	39
Deferred income taxes and amortization of investment tax credits	13	(4)
Other non-cash operating activities	(7)	118
Changes in assets and liabilities:		
Accounts receivable	6	4
Receivables from and payables to affiliates, net	1	20
Inventories	1	1
Accounts payable and accrued expenses	14	(3)
Income taxes	21	52
Other assets and liabilities	(23)	(8)
Net cash flows provided by operating activities	122	147
Cash flows from investing activities		
Capital expenditures	(82)	(81)
Other investing activities	2	
Net cash flows used in investing activities	(80)	(81)
Cash flows from financing activities		
Changes in short-term borrowings		(30)
Retirement of long-term debt	(14)	
Dividends paid on common stock	(30)	(38)
Net cash flows used in financing activities	(44)	(68)
Decrease in cash and cash equivalents	(2)	(2)
Cash and cash equivalents at beginning of period	46	5
Cash and cash equivalents at end of period	$ 44	$ 3

See the Combined Notes to Consolidated Financial Statements

Table of Contents

DELMARVA POWER & LIGHT COMPANY

BALANCE SHEETS

(Unaudited)

(In millions)	March 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 44	$ 46
Accounts receivable, net		
Customer	131	136
Other	39	63
Receivables from affiliates		3
Inventories, net		
Gas held in storage	3	7
Materials and supplies	35	32
Regulatory assets	66	59
Other	21	24
Total current assets	339	370
Property, plant and equipment, net	3,334	3,273
Deferred debits and other assets		
Regulatory assets	301	289
Investments	1	
Goodwill	8	8
Prepaid pension asset	203	206
Other	5	7
Total deferred debits and other assets	518	510
Total assets	$ 4,191	$ 4,153

See the Combined Notes to Consolidated Financial Statements

Table of Contents

DELMARVA POWER & LIGHT COMPANY

BALANCE SHEETS

(Unaudited)

(In millions)	March 31, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Long-term debt due within one year	$ 109	$ 119
Accounts payable	106	88
Accrued expenses	44	36
Payables to affiliates	36	38
Customer deposits	36	36
Regulatory liabilities	47	43
Merger related obligation	4	13
Other	6	8
Total current liabilities	388	381
Long-term debt	1,217	1,221
Deferred credits and other liabilities		
Regulatory liabilities	95	97
Deferred income taxes and unamortized investment tax credits	1,072	1,056
Non-pension postretirement benefit obligations	17	19
Other	49	53
Total deferred credits and other liabilities	1,233	1,225
Total liabilities	2,838	2,827
Commitments and contingencies		
Shareholder s equity		
Common stock	764	764
Retained earnings	589	562
Total shareholder s equity	1,353	1,326
Total liabilities and shareholder s equity	$ 4,191	$ 4,153

See the Combined Notes to Consolidated Financial Statements

49

Table of Contents

DELMARVA POWER & LIGHT COMPANY

STATEMENT OF CHANGES IN SHAREHOLDER S EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholder s Equity
Balance, December 31, 2016	$ 764	$ 562	$ 1,326
Net income		57	57
Common stock dividends		(30)	(30)
Balance, March 31, 2017	$ 764	$ 589	$ 1,353

See the Combined Notes to Consolidated Financial Statements

Table of Contents

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended March 31, 2017	2016
Operating revenues		
Electric operating revenues	$ 274	$ 290
Operating revenues from affiliates	1	1
Total operating revenues	275	291
Operating expenses		
Purchased power	128	157
Purchased power from affiliates	9	1
Operating and maintenance	69	211
Operating and maintenance from affiliates	7	1
Depreciation and amortization	35	40
Taxes other than income	2	2
Total operating expenses	250	412
Operating income (loss)	25	(121)
Other income and (deductions)		
Interest expense, net	(15)	(16)
Other, net	2	4
Total other income and (deductions)	(13)	(12)
Income (loss) before income taxes	12	(133)
Income taxes	(16)	(33)
Net income (loss)	$ 28	$ (100)
Comprehensive income (loss)	$ 28	$ (100)

See the Combined Notes to Consolidated Financial Statements

Table of Contents

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Cash flows from operating activities		
Net income (loss)	$ 28	$ (100)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation and amortization	35	40
Deferred income taxes and amortization of investment tax credits	(7)	(33)
Other non-cash operating activities	2	132
Changes in assets and liabilities:		
Accounts receivable	14	5
Receivables from and payables to affiliates, net	(5)	20
Inventories	(1)	(2)
Accounts payable and accrued expenses	(5)	19
Income taxes	3	168
Other assets and liabilities	(6)	(3)
Net cash flows provided by operating activities	58	246
Cash flows from investing activities		
Capital expenditures	(88)	(101)
Changes in restricted cash	2	1
Other investing activities	1	
Net cash flows used in investing activities	(85)	(100)
Cash flows from financing activities		
Changes in short-term borrowings		(5)
Retirement of long-term debt	(10)	(11)
Dividends paid on common stock	(10)	(11)
Net cash flows used in financing activities	(20)	(27)
(Decrease) Increase in cash and cash equivalents	(47)	119
Cash and cash equivalents at beginning of period	101	3
Cash and cash equivalents at end of period	$ 54	$ 122

See the Combined Notes to Consolidated Financial Statements

Table of Contents

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	March 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 54	$ 101
Restricted cash and cash equivalents	7	9
Accounts receivable, net		
Customer	111	125
Other	41	44
Inventories, net	23	22
Regulatory assets	94	96
Other	3	2
Total current assets	333	399
Property, plant and equipment, net	2,583	2,521
Deferred debits and other assets		
Regulatory assets	407	405
Long-term note receivable	4	4
Prepaid pension asset	82	84
Other	42	44
Total deferred debits and other assets	535	537
Total assets[(a)]	$ 3,451	$ 3,457

See the Combined Notes to Consolidated Financial Statements

53

Table of Contents

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	March 31, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Long-term debt due within one year	$ 33	$ 35
Accounts payable	125	132
Accrued expenses	50	38
Payables to affiliates	24	29
Customer deposits	32	33
Regulatory liabilities	25	25
Merger related obligation	22	20
Other	9	8
Total current liabilities	320	320
Long-term debt	1,112	1,120
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	911	917
Non-pension postretirement benefit obligations	33	34
Other	23	32
Total deferred credits and other liabilities	967	983
Total liabilities[(a)]	2,399	2,423
Commitments and contingencies		
Shareholder s equity		
Common stock	912	912
Retained earnings	140	122
Total shareholder s equity	1,052	1,034
Total liabilities and shareholder s equity	$ 3,451	$ 3,457

(a) ACE s consolidated total assets include $30 million and $32 million at March 31, 2017 and December 31, 2016, respectively, of ACE s consolidated VIE that can only be used to settle the liabilities of the VIE. ACE s consolidated total liabilities include $115 million and $126 million at March 31, 2017 and December 31, 2016, respectively, of ACE s consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 3 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDER S EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholder s Equity
Balance, December 31, 2016	$ 912	$ 122	$ 1,034
Net income		28	28
Common stock dividends		(10)	(10)
Balance, March 31, 2017	$ 912	$ 140	$ 1,052

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

Registrant	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Exelon Corporation	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
Exelon Generation Company, LLC	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		.	.	.	.
Commonwealth Edison Company	.	.	.		.			.	.	.	.		.	.			.	.	.	
PECO Energy Company	.	.	.		.			.	.	.	.		.	.	.		.	.	.	
Baltimore Gas and Electric Company	.	.	.		.			.	.	.	.		.	.			.	.	.	
Pepco Holdings LLC	.	.	.	.	.			.	.	.	.		.	.	.		.	.	.	
Potomac Electric Power Company	.	.	.		.			.	.	.	.		.	.			.	.	.	
Delmarva Power & Light Company	.	.	.		.			.	.	.	.		.	.			.	.	.	
Atlantic City Electric Company	.	.	.		.			.	.	.	.		.	.			.	.	.	

1. 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.

Pepco: Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in the District of Columbia and major portions of Prince George s County and Montgomery County in Maryland.

DPL: Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in northern Delaware.

ACE: Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in southern New Jersey.

Basis of Presentation (All Registrants)

As a result of the acquisition of PHI, Exelon s financial reporting reflects PHI s consolidated financial results subsequent to the March 23, 2016, acquisition date. Exelon has accounted for the merger transaction applying the acquisition method of accounting, which requires 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.

In the second quarter of 2016, an error was identified and corrected 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. As revised for the first quarter of 2017, the successor period statement of cash flows for the period March 24, 2016 to March 31, 2016 presents 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.

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 March 31, 2017 and 2016 and for the three months then ended are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2016 Consolidated Balance Sheets were derived from audited financial statements. Financial results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for the fiscal year ending December 31, 2017. These Combined Notes to Consolidated Financial Statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

2. New Accounting Standards (All Registrants)

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

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

The new standard replaces existing guidance on revenue recognition, including most industry specific guidance, with a five step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries, and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows. In addition, the Registrants will be required to capitalize costs to acquire new contracts, and amortize such costs in a manner consistent with the transfer to the customer of the associated goods or services. Exelon currently expenses those costs as incurred. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method).

The Registrants continue to assess the impacts this guidance may have on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. In performing this assessment, the Registrants have utilized a project implementation team comprised of both internal and external resources to conduct the following key activities:

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

- Evaluate existing contracts and revenue streams for potential changes in the amounts and timing of recognizing revenues under the new guidance;

- Evaluate and select the transition method; and

- Develop and implement the approach and process for complying with the new revenue recognition disclosure requirements.

While there continues to be some ongoing activities in all of these areas, the Registrants have substantially completed the evaluation of their collective contracts and revenue streams, as well as the evaluation of the

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

transition method. Based on the work completed thus far, the Registrants have reached the following preliminary conclusions:

- The Registrants expect to apply the new guidance using the full retrospective method, however this conclusion could change based on the outcome of open implementation issues discussed below;

- The Registrants currently anticipate that the implementation of the new guidance will not have a material impact on the amount and timing of revenue recognition; and

- The new guidance will result in more detailed disclosures of revenue compared to current guidance.

Notwithstanding the preliminary conclusions noted above, certain implementation issues continue to be debated and worked through the Industry Task Force process that could result in amendments to the standard or implementation guidance that could have a material impact on the Registrants Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. The contributions in aid of construction (CIAC) implementation issue previously disclosed has been resolved, subject to the completion of the public comment period, with the conclusion that CIAC is outside of the scope of ASC 606 and, therefore, the accounting by the Utility Registrants for CIAC will not change as a result of ASC 606. The open implementation issues that could be most impactful to the Registrants include: (1) the ability of the Utility Registrants to recognize revenue for certain contracts where collectability is in question and (2) primarily at Generation, bundled sales contracts and contracts with pricing provisions that may require recognition of revenue at prices other than the contract price (e.g., straight line or estimated future market prices). As part of the overall implementation project, the Registrants have developed alternative adoption plans that would be implemented in the event the ultimate resolution of the open implementation issues result in significant changes from current revenue recognition practices.

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

Exelon is currently evaluating the impact of this standard, including coordinating with its industry group and advisors. Generation, ComEd, PECO, BGE, BSC, PHI, Pepco, DPL, ACE and PHISCO participate in Exelon s single employer plan and apply multi-employer accounting. Exelon is currently evaluating how the new standard will impact accounting and financial reporting for these registrants.

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

Leases (Issued February 2016): Increases transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The guidance requires lessees to recognize both the right-of-use assets and lease liabilities in the balance sheet for most leases, whereas today only financing type lease liabilities (capital leases) are recognized in the balance sheet. This is expected to require significant changes to systems, processes and procedures in order to

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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. Early adoption is permitted, however the Registrants do not expect to early adopt the standard. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. Refer to Note 24 Commitments and Contingencies of the Combined Notes to the Consolidated Financial Statements in the Exelon 2016 Form 10-K for additional information regarding operating leases.

Impairment of Financial Instruments (Issued June 2016): Provides for a new Current Expected Credit Loss (CECL) impairment model for specified financial instruments including loans, trade receivables, debt securities classified as held-to-maturity investments and net investments in leases recognized by a lessor. Under the new guidance, on initial recognition and at each reporting period, an entity is required to recognize an allowance that reflects the entity s current estimate of credit losses expected to be incurred over the life of the financial instrument. The standard does not make changes to the existing impairment models for non-financial assets such as fixed assets, intangibles and goodwill. The standard will be effective January 1, 2020 and, for most debt instruments, requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption.

Goodwill Impairment (issued January 2017): Simplifies the accounting for goodwill impairment by removing Step 2 of the current test, which requires calculation of a hypothetical purchase price allocation. Under the revised guidance, goodwill impairment will be measured as the amount by which a reporting unit s carrying value exceeds its fair value, not to exceed the carrying amount of goodwill (currently Step 1 of the two step impairment test). Entities will continue to have the option to perform a qualitative assessment to determine if a quantitative impairment test is necessary. Exelon, Generation, ComEd, PHI, and DPL have goodwill as of March 31, 2017. This updated guidance is not currently expected to impact the Registrants financial reporting. The standard is effective January 1, 2020, with early adoption permitted, and must be adopted on a prospective basis.

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

Intra-Entity Transfers of Assets Other Than Inventory (Issued October 2016): Requires entities to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs (compared to current GAAP which prohibits the recognition of current and deferred income taxes for an intra-entity asset transfer until the asset has been sold to an outside party). The standard is effective for fiscal years beginning after December 15, 2017 with early adoption permitted. The guidance is required to be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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 March 31, 2017 and December 31, 2016, Exelon, Generation, BGE, PHI and ACE collectively consolidated nine VIEs or VIE groups, for which the applicable Registrant was the primary beneficiary (*see Consolidated Variable Interest Entities below*). As of March 31, 2017 and December 31, 2016, Exelon and Generation collectively had significant interests in seven and eight, respectively, other VIEs for which the applicable Registrant does not have the power to direct the entities activities and, accordingly, was not the primary beneficiary (*see Unconsolidated Variable Interest Entities below).*

Consolidated Variable Interest Entities

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,

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

a group of solar project limited liability companies formed by Generation to build, own and operate solar power facilities,

several wind project companies designed by Generation to develop, construct and operate wind generation facilities,

a group of companies formed by Generation to build, own and operate other generating facilities,

certain retail power and gas companies for which Generation is the sole supplier of energy,

CENG,

2015 ESA Investco, LLC, a company that holds an equity method investment in a distributed energy company,

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 March 31, 2017 and December 31, 2016, ComEd, PECO, Pepco and DPL did not have any material consolidated VIEs.

As of March 31, 2017 and December 31, 2016, 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 provides approximately $27 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.

Generation and Exelon, where indicated, provide the following support to CENG (see Note 5 Investment in Constellation Energy Nuclear Group, LLC and Note 27 Related Party Transactions of the Exelon 2016 Form 10-K for additional information regarding Generation s and Exelon s transactions with CENG):

under the NOSA, Generation conducts all activities related to the operation of the CENG nuclear generation fleet owned by CENG subsidiaries (the CENG fleet) and provides corporate and administrative services for the remaining life and decommissioning of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF,

under the Power Services Agency Agreement (PSAA), Generation provides scheduling, asset management, and billing services to the CENG fleet for the remaining operating life of the CENG nuclear plants,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 March 31, 2017, the remaining obligation is $320 million, including accrued interest, which reflects the principal payment made in January 2015,

Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation s obligations under this Indemnity Agreement. (See Note 17 Commitments and Contingencies for more details),

Generation and EDF share in the $637 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance,

Generation provides a guarantee of approximately $8 million associated with hazardous waste management facilities and underground storage tanks. In addition, EDF executed a reimbursement agreement that provides reimbursement to Exelon for 49.99% of any amounts paid by Generation under this guarantee,

Generation and EDF are the members-insured with Nuclear Electric Insurance Limited and have assigned the loss benefits under the insurance and the NEIL premium costs to CENG and guarantee the obligations of CENG under these insurance programs in proportion to their respective member interests (see Note 17 Commitments and Contingencies for more details), and

Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG s cash pooling agreement with its subsidiaries.

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 months ended March 31, 2017 and 2016, BGE remitted $19 million and $20 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 months ended March 31, 2017 and 2016, ACE transferred $19 million and $14 million to ATF, respectively.

For each of the consolidated VIEs, except as otherwise noted:

the assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE;

Exelon, Generation, 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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

the creditors of the VIEs did not have recourse to Exelon s, Generation s, BGE s, PHI s or ACE s general credit.
The carrying amounts and classification of the consolidated VIEs assets and liabilities included in the Registrants consolidated financial statements at March 31, 2017 and December 31, 2016 are as follows:

	March 31, 2017					December 31, 2016				
	Exelon[(a)]	Generation	BGE	*Successor* PHI[(a)]	ACE	Exelon[(a)(b)]	Generation	BGE	*Successor* PHI[(a)]	ACE
Current assets	$ 1,018	$ 965	$ 42	$ 11	$ 7	$ 954	$ 916	$ 23	$ 14	$ 9
Noncurrent assets	8,891	8,855	3	33	23	8,563	8,525	3	35	23
Total assets	$ 9,909	$ 9,820	$ 45	$ 44	$ 30	$ 9,517	$ 9,441	$ 26	$ 49	$ 32
Current liabilities	$ 871	$ 791	$ 42	38	$ 34	$ 885	$ 802	$ 42	$ 42	$ 37
Noncurrent liabilities	2,745	2,654		91	81	2,713	2,612		101	89
Total liabilities	$ 3,616	$ 3,445	$ 42	$ 129	$ 115	$ 3,598	$ 3,414	$ 42	$ 143	$ 126

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

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

	March 31, 2017					December 31, 2016				
	Exelon[(a)]	Generation	BGE	*Successor* PHI [(a)]	ACE	Exelon[(a)(b)]	Generation	BGE	*Successor* PHI [(a)]	ACE
Cash and cash equivalents	$ 199	$ 199	$	$	$	$ 150	$ 150	$	$	$
Restricted cash	124	75	42	7	7	59	27	23	9	9
Accounts receivable, net										
Customer	347	347				371	371			
Other	23	23				48	48			
Mark-to-market derivatives assets	41	41				31	31			
Inventory										
Materials and supplies	191	191				199	199			
Other current assets	58	54		4		50	44		5	
Total current assets	983	930	42	11	7	908	870	23	14	9
Property, plant and equipment, net	5,425	5,425				5,415	5,415			
Nuclear decommissioning trust funds	2,286	2,286				2,185	2,185			
Goodwill	47	47				47	47			
Mark-to-market derivatives assets	57	57				23	23			
Other noncurrent assets	350	314	3	33	23	315	277	3	35	23
Total noncurrent assets	8,165	8,129	3	33	23	7,985	7,947	3	35	23
Total assets	$ 9,148	$ 9,059	$ 45	$ 44	$ 30	$ 8,893	$ 8,817	$ 26	$ 49	$ 32
Long-term debt due within one year	$ 237	$ 159	$ 41	$ 37	$ 33	$ 181	$ 99	$ 41	$ 40	$ 35
Accounts payable	275	275				269	269			
Accrued expenses	85	83	1	1	1	119	116	1	2	2
Mark-to-market derivative liabilities	18	18				60	60			
Unamortized energy contract liabilities	16	16				15	15			
Other current liabilities	11	11				30	30			
Total current liabilities	642	562	42	38	34	674	589	42	42	37
Long-term debt	626	535		91	81	641	540		101	89
Asset retirement obligations	1,929	1,929				1,904	1,904			
Pension obligation[(c)]	8	8				9	9			
Unamortized energy contract liabilities	18	18				22	22			
Other noncurrent liabilities	122	122				106	106			
Total noncurrent liabilities	2,703	2,612		91	81	2,682	2,581		101	89

Total liabilities	$ 3,345	$ 3,174	$ 42	$ 129	$ 115	$ 3,356	$ 3,170	$ 42	$ 143	$ 126

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

Table of Contents

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

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

In June 2015, 2015 ESA Investco, LLC, then a wholly owned subsidiary of Generation, entered into an arrangement to purchase a 90% equity interest and 99% of the tax attributes of a distributed energy company, which is an unconsolidated VIE. In November 2015, Generation sold 69% of its equity interest in 2015 ESA Investco, LLC to a tax equity investor. Generation and the tax equity investor contributed a total of $227 million of equity incrementally from inception through the first quarter of 2017 in proportion of their ownership interests. Generation and the tax equity investor provided a parental guarantee of up to $275 million in proportion to their ownership interests in support of 2015 ESA Investco, LLC s obligation to make equity contributions to the distributed energy company. As all equity contributions were made as of March 31, 2017, there is no further payment obligation under the parental guarantee.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

March 31, 2017	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[a]	$ 647	$ 541	$ 1,188
Total liabilities[a]	73	230	303
Exelon s ownership interest in VIE[a]		276	276
Other ownership interests in VIE[a]	574	36	610
Registrants maximum exposure to loss:			
Carrying amount of equity method investments		279	279
Contract intangible asset	9		9
Debt and payment guarantees			
Net assets pledged for Zion Station decommissioning[b]	7		7

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

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon s or Generation s Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.

(b) These items represent amounts on Exelon s and Generation s Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $95 million and $113 million as of March 31, 2017 and December 31, 2016, respectively; offset by payables to ZionSolutions LLC of $88 million and $104 million as of March 31, 2017 and December 31, 2016, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

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.

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

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

On March 31, 2017, Generation acquired the 838 MW single-unit James A. FitzPatrick (FitzPatrick) nuclear generating station located in Scriba, New York from Entergy Nuclear FitzPatrick LLC (Entergy) for a total purchase price of $293 million, which consisted of a cash purchase price of $110 million and a net cost reimbursement to and on behalf of Entergy of $183 million. As part of the acquisition agreements, Generation provided nuclear fuel and reimbursed Entergy for incremental costs to prepare for and conduct a plant refueling outage; and Generation reimbursed Entergy for incremental costs to operate and maintain the plant for the period

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

after the refueling outage through the acquisition closing date. These reimbursements covered costs that Entergy otherwise would have avoided had it shut down the plant as originally intended in January 2017. The amounts reimbursed by Generation were offset by FitzPatrick s electricity and capacity sales revenues for this same post-outage period. As part of the transaction, Generation received the FitzPatrick NDT fund assets and assumed the obligation to decommission FitzPatrick. The NRC license for FitzPatrick expires in 2034. As of March 31, 2017, Generation had remitted purchase price consideration of $302 million (including $248 million of cash and $54 million of nuclear fuel) to and on behalf of Entergy and has $9 million included in Accounts receivable, net Other on Exelon s and Generation s Consolidated Balance Sheets, to be received during the second quarter of 2017.

The following table summarizes the acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for the FitzPatrick acquisition by Generation as of March 31, 2017:

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

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

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

The fair values of FitzPatrick s assets and liabilities were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing), discount rates reflecting risk inherent in the future cash flows and future power and fuel market prices. The valuations performed to assess the fair value of certain assets acquired and liabilities assumed are preliminary. Accounting guidance provides that the allocation of the purchase price may be modified up to one year from the date of the

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

acquisition to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date; however, Generation expects to finalize these amounts by the end of 2017. The significant assets and liabilities for which preliminary valuation amounts are recognized at March 31, 2017 include the fair value of the decommissioning ARO, pension and OPEB obligations and related deferred tax liabilities. Any changes to the fair value assessments may materially impact the purchase price allocation and the amount of the recorded bargain purchase gain.

For the three months ended March 31, 2017, Exelon and Generation incurred $32 million of merger and integration related costs which are included within Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income.

Merger with Pepco Holdings, Inc. (Exelon)

Description of Transaction

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

Regulatory Matters

Approval of the merger in Delaware, New Jersey, Maryland and the District of Columbia was conditioned upon Exelon and PHI agreeing to certain commitments including where applicable: customer rate credits, funding for energy efficiency and delivery system modernization programs, a green sustainability fund, workforce development initiatives, charitable contributions, renewable generation and other required commitments. In addition, the orders approving the merger in Delaware, New Jersey, and Maryland include a most favored nation provision which, generally speaking, requires allocation of merger benefits proportionally across all the jurisdictions.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

					Successor	
Description	**Expected Payment Period**	**Pepco**	**DPL**	**ACE**	**PHI**	**Exelon**
Rate credits	2016 2017	$ 91	$ 66	$ 101	$ 258	$ 258
Energy efficiency	2016 2021					122
Charitable contributions	2016 2026	28	12	10	50	50
Delivery system modernization	Q2 2016					22
Green sustainability fund	Q2 2016					14
Workforce development	2016 2020					17
Other		7	7		14	30
Total		$ 126	$ 85	$ 111	$ 322	$ 513

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

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

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

In July 2015, the OPC, Public Citizen, Inc., the Sierra Club and the Chesapeake Climate Action Network (CCAN) filed motions to stay the MDPSC order approving the merger. The Circuit Court judge issued an order denying the motions for stay on August 12, 2015. On January 8, 2016, the Circuit Court judge affirmed the MDPSC s order approving the merger and denied the petitions for judicial review filed by the OPC, the Sierra Club, CCAN and Public Citizen, Inc. On January 19, 2016, the OPC filed a notice of appeal to the Maryland Court of Special Appeals, and on January 21, the Sierra Club and CCAN filed a notice of appeal. On January 27, 2017, the Maryland Court of Special Appeals affirmed the Circuit Court s judgment. The OPC and Sierra Club have each filed petitions seeking further review in the Court of Appeals of Maryland. Exelon, along with Prince George s County and Montgomery County have filed answers opposing those petitions, which Exelon believes are without merit.

Between March 25, 2016 and April 22, 2016, various parties filed motions with the DCPSC to reconsider its March 23, 2016 order approving the merger. On June 17, 2016, the DCPSC denied all motions. In August 2016, the District of Columbia Office of People s Counsel, the District of Columbia Government, and Public Citizen jointly with DC Sun each filed petitions for judicial review of the DCPSC s March 23, 2016 order with the District of Columbia Court of Appeals. On September 9, 2016, the Court consolidated the appeals. The parties have filed briefs and the Court scheduled oral argument for May 2. A decision on this matter is expected in the second or third quarter of 2017. Exelon believes the matters are without merit.

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:

(In millions of dollars, except per share data)	**Total Consideration**
Cash paid to PHI shareholders at $27.25 per share (254 million shares outstanding at March 23, 2016)	$ 6,933
Cash paid for PHI preferred stock[a]	180
Cash paid for PHI stock-based compensation equity awards[b]	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 preliminary valuations performed in the first quarter of 2016 were updated in the second, third, and fourth quarters of 2016. There were no adjustments to the purchase price allocation in the first quarter of 2017 and the purchase price allocation is now final.

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:

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

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

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

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

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

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

Through its wholly-owned rate regulated utility subsidiaries, most of PHI s assets and liabilities are subject to cost-of-service rate regulation. Under such regulation, rates charged to customers are established by a

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 March 31, 2017. The difference between the contract price and the market price at the acquisition date of the Merger was recognized for each contract as either an intangible asset or liability. In total, Exelon and PHI recorded a net $1.5 billion liability reflecting out-of-the-money contracts. The valuation of the acquired intangible assets and liabilities was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. In certain instances, the valuations were based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power prices and the discount rate. The unamortized energy contract fair value adjustment amounts and the corresponding offsetting regulatory asset and liability amounts are amortized through Purchase power and fuel expense or Operating revenues, as applicable, over the life of the applicable contract in relation to the present value of the underlying cash flows as of the merger date.

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

The current impact of PHI, including its unregulated businesses, on Exelon s Consolidated Statements of Operations and Comprehensive Income includes Operating revenues of $1.2 billion and Net income of $140 million during the three months ended March 31, 2017, and Operating revenues of $107 million and Net loss of $(315) million during the three months ended March 31, 2016.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

For the three months ended March 31, 2017 and 2016, the Registrants have recognized costs to achieve the PHI acquisition as follows:

Acquisition, Integration and Financing Costs[(a)]	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Exelon[(b)]	$ 9	$ 102
Generation	9	16
ComEd[(c)]		(8)
PECO	1	2
BGE	2	2
Pepco	1	27
DPL[(d)]	(7)	16
ACE	1	13

	Successor		*Predecessor*
Acquisition, Integration and Financing Costs[(a)]	**Three Months Ended March 31, 2017**	**March 24, 2016 to March 31, 2016**	**January 1, 2016 to March 23, 2016**
PHI[(d)]	$ (5)	$ 56	$ 29

(a) The costs incurred are classified primarily within Operating and maintenance expense in the Registrants respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the financing costs, which are included within Interest expense. Costs do not include merger commitments discussed above.
(b) Reflects costs (benefits) recorded at Exelon related to financing, including mark-to-market activity on forward-starting interest rate swaps.
(c) For the three months ended March 31, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $9 million, incurred at ComEd that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 Regulatory Matters for more information.
(d) For the three months ended March 31, 2017, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million, incurred at DPL that have been deferred and recorded as a regulatory asset for anticipated recovery. 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.

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 March 31, 2016[(a)]	Year Ended December 31, 2016[(b)]
Total operating revenues	$ 8,556	$ 32,342

Net income attributable to common shareholders		577		1,562
Basic earnings per share	$	0.63	$	1.69
Diluted earnings per share		0.62		1.69

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(a) The amounts above include adjustments for non-recurring costs directly related to the merger of $639 million and intercompany revenue of $170 million for the three months ended March 31, 2016.
(b) The amounts above include adjustments for non-recurring costs directly related to the merger of $680 million and intercompany revenue of $171 million for the year ended December 31, 2016.

5. Regulatory Matters (All Registrants)

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

Illinois Regulatory Matters

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

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

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

Background

On December 7, 2016, FEJA was signed into law by the Governor of Illinois. FEJA is effective June 1, 2017, and includes, among other provisions, (1) a ZES providing compensation for certain nuclear-powered generating facilities, (2) an extension of and certain adjustments to ComEd s electric distribution formula rate, (3) new cumulative persisting annual energy efficiency MWh savings goals for ComEd, (4) revisions to the Illinois RPS requirements, (5) provisions for adjustments to or termination of FEJA programs if the average impact on ComEd s customer rates exceeds specified limits, (6) revisions to the existing net metering statute to (i) mandate net metering for community generation projects, and establish billing procedures for subscribers to those projects, (ii) provide immediately for netting at the energy-only rate for nonresidential customers, and

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(iii) transition from netting at the full retail rate to the energy-only rate for certain residential net metering customers once the net meter customer load equals 5% of total peak demand supplied in the previous year and (7) support for low income rooftop and community solar programs.

Zero Emission Standard

FEJA includes a ZES that provides compensation through the procurement of ZECs targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet specific eligibility criteria. ZES will have a 10-year duration extending through May 31, 2027. Eligible generators may participate in a procurement event overseen by the IPA and selected generators will directly contract with Illinois utilities for the procurement of the ZECs based upon the number of MWh produced by the eligible facilities, subject to specified annual caps. The ZEC price will be based upon the current social cost of carbon as determined by the federal government and is initially established at $16.50 per MWh of production, subject to future adjustments based on specified escalation and pricing adjustment mechanisms designed to lower the ZEC price based on increases in underlying energy and capacity prices.

Illinois utilities, including ComEd, will be required to purchase from eligible nuclear facilities an amount of ZECs equivalent to 16% of the actual amount of electricity delivered in 2014. ComEd will recover all costs associated with purchasing ZECs through a new rate rider, which will provide for an annual reconciliation and true-up to actual costs incurred by ComEd to purchase ZECs, with any difference to be credited to or collected from ComEd s retail customers in subsequent periods.

On February 14, 2017, two lawsuits were filed in the Northern District of Illinois against the IPA alleging that the state s ZEC program violates certain provisions of the U.S. Constitution. One lawsuit was filed by customers of ComEd, led by the Village of Old Mill Creek, and the other was brought by the EPSA and three other electric suppliers. Both lawsuits argue that the Illinois ZEC program will distort FERC s energy and capacity market auction system of setting wholesale prices, and seek a permanent injunction preventing the implementation of the program. Exelon intervened and filed motions to dismiss in both lawsuits. These motions are currently pending. In addition, on March 31, 2017, plaintiffs in both lawsuits filed motions for preliminary injunction with the court. Exelon cannot predict the outcome of these lawsuits. It is possible that resolution of these matters could have a material, unfavorable impact on Exelon s and Generation s results of operations, financial positions and cash flows.

See Note 7 Early Nuclear Plant Retirements for the impacts of the provisions above on Generation s Consolidated Balance Sheets and Consolidated Statements of Operations and Comprehensive Income. These provisions do not impact ComEd s Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income or Consolidated Statements of Cash Flows until second quarter of 2017.

ComEd Electric Distribution Rates

FEJA extends the sunset date for ComEd s performance-based electric distribution formula rate from 2019 to the end of 2022, allows ComEd to revise the electric distribution formula rate to eliminate the ROE collar, and allows ComEd to implement a decoupling tariff if the electric distribution formula rate is terminated at any time. ComEd will revise its electric distribution formula rate to eliminate the ROE collar beginning with the reconciliation filed in 2018 for the 2017 calendar year. Elimination of the ROE collar effectively offsets the favorable or unfavorable impacts to Operating revenues associated with variations in delivery volumes associated with above or below normal weather, numbers of customers or usage per customer. ComEd began reflecting the impacts of this change in its electric distribution services costs regulatory asset beginning in first quarter 2017. As of March 31, 2017, ComEd recorded an increase to Operating revenues and its electric distribution services costs regulatory asset of approximately $16 million for this change.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Energy Efficiency

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

Beginning January 1, 2018, FEJA provides for new cumulative annual energy efficiency MWh savings goals for ComEd, which are designed to achieve 21.5% of cumulative persisting annual MWh savings by 2030, as compared to the deemed baseline of 88 million MWhs of electric power and energy sales. FEJA, deems the cumulative persisting annual MWh savings to be 6.6% from 2012 through the end of 2017. ComEd expects to spend approximately $250 million to $400 million annually from 2017 through 2030 to achieve these energy efficiency MWh savings goals. In addition, FEJA extends the peak demand reduction requirement from 2018 to 2026. Because the new requirements apply beginning in 2018, FEJA extends the existing energy efficiency plans, which were due to end on May 31, 2017, through December 31, 2017. FEJA also exempts customers with demands over 10 MW from energy efficiency plans and requirements beginning June 1, 2017.

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

ComEd expects to cancel its existing energy efficiency rider after FEJA becomes effective on June 1, 2017, at which time it must perform a reconciliation of revenues and costs incurred through the cancellation date and issue a one-time credit on retail customers bills for any over-recoveries. As of March 31, 2017, ComEd s over-recoveries associated with its existing energy efficiency rider of $139 million were reflected in Current regulatory liabilities on Exelon s and ComEd s Consolidated Balance Sheets. ComEd expects to provide a one-time credit to customers in the second half of 2017 to address this over-recovery.

Renewable Portfolio Standard

Existing Illinois law requires ComEd to purchase each year an increasing percentage of renewable energy resources for the customers for which it supplies electricity. This obligation is satisfied through the procurement of RECs. FEJA revises the Illinois RPS to require ComEd to procure RECs for all retail customers by June 2019, regardless of the customers electricity supplier, and provides support for low-income rooftop and community solar programs, which will be funded by the existing Renewable Energy Resources Fund and ongoing RPS collections. ComEd will recover all costs associated with purchasing RECs through rate riders, which will provide for a reconciliation and true-up to actual costs, with any difference between revenues and expenses to be credited to or collected from ComEd s retail customers in subsequent periods. The first reconciliation and true-up for RECs will cover revenues and costs for the four year period beginning June 1, 2017 through May 31, 2021. Subsequently, the RPS rate rider will provide for an annual reconciliation and true-up.

Customer Rate Increase Limitations

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

By June 30, 2017, ComEd must submit a 10-year projection to the ICC of customer rate impacts for residential customers and nonresidential customers with a peak demand less than 10 MW. Thereafter, beginning in 2018, ComEd must submit a report to the ICC for residential customers and nonresidential customers with a peak demand less than 10 MW by February 15th and June 30th of each year, respectively. For nonresidential customers with a peak demand greater than 10 MW, ComEd must submit a report to the ICC by May 1 of each year if a rate reduction will be necessary in the following year. For residential customers, the reports will include the actual costs incurred under FEJA during the preceding year and a rolling 10-year customer rate impact projection. The reports for nonresidential customers with a peak demand less than 10 MW will also include the actual costs incurred under FEJA during the preceding year, as well as the average annual rate increase from January 1, 2017 through the end of the preceding year and the average annual rate increase projected for the remainder of the 10-year period.

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

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

Other than recognizing the impacts of eliminating the ROE collar in its electric distribution formula rate, FEJA did not have any impacts on ComEd s Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income or Consolidated Statements of Cash Flows in first quarter 2017.

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

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

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. ComEd acquired the necessary land rights across the project route through voluntary transactions. ComEd began construction of the line during 2015 and placed the line in-service on April 7, 2017.

Pennsylvania Regulatory Matters

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

On March 17, 2016, PECO filed its fourth DSP Program with the PAPUC proposing a 24-month term from June 1, 2017 through May 31, 2019, in compliance with electric generation procurement guidelines set forth in Act 129. On December 8, 2016, the PAPUC approved the fourth DSP Program for the modified 48-month term

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

and deferred CAP Shopping to another proceeding. OCA and Low Income Advocates subsequently filed a Petition for Reconsideration and Clarification related to CAP Shopping. On March 16, 2017 the PAPUC granted reconsideration and consolidated the proceeding with the DSP II docket, which includes the pending CAP Shopping plan that would allow low-income CAP customers to purchase their generation supply from EGSs. PAPUC referred the consolidated proceedings to the Office of Administrative Law Judge for hearing and decision.

Pennsylvania Act 11 of 2012 (Exelon and PECO). In February 2012, Act 11 was signed into law, which provided the PAPUC authority to approve the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities aging electric and natural gas distribution systems in Pennsylvania. Prior to recovering costs pursuant to a DSIC, the PAPUC s implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIP) approved by the Commission, which outlines how the utility is planning to increase its investment for repairing, improving or replacing aging infrastructure. The PAPUC approved PECO s petition for its proposed electric DSIC and LTIIP on October 22, 2015 for spending of $275 million over a 5 year period through 2020. On March 1, 2017, PECO filed a petition with the PAPUC for approval of a Modified Gas LTIIP to increase expenditures to $762 million from the approved $534 million over the 10 year LTIIP period through 2022.

Maryland Regulatory Matters

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

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 March 31, 2017 and December 31, 2016, the balance of BGE s regulatory asset was $225 million and $230 million, respectively, representing incremental program deployment costs. The current quarter balance of $225 million consists of three major components, including $140 million of unamortized incremental deployment costs of the AMI program, $53 million of unamortized costs of the non-AMI meters replaced under the program, and $32 million related to post-test year incremental program deployment costs incurred prior to approval became effective June 2016. The balance as of March 31, 2017 reflects the impact of the cost disallowances and adjustments discussed below. The incremental deployment costs for the AMI program and the non-AMI meter components of the regulatory asset are being recovered through rates and amortized to expense over a 10 year period, while the post-test year incremental program deployment costs have not yet been approved for recovery by the MDPSC. A return on the regulatory asset is currently included in rates, except for the $53 million portion representing the unamortized cost of the retired non-AMI meters and a $32 million portion related to post-test year incremental program deployment costs.

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

Delaware Regulatory Matters

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

2016 Electric and Natural Gas Distribution Rates (Exelon, PHI and DPL). On May 17, 2016, DPL filed an application with the DPSC to increase its annual electric and natural gas distribution rates by $63 million (which was updated to $60 million on March 8, 2017) and $22 million, respectively, based on a requested ROE of 10.6%. While the DPSC is not required to issue a decision on the application within a specified period of time, Delaware law allowed DPL to put into effect $2.5 million of each of the rate increases two months after filing the applications which were effective July 16, 2016. On December 17, 2016, the DPSC approved that an additional $30 million in electric distribution rates be implemented effective December 17, 2016, subject to refund based on the final DPSC order, and an additional $10 million in natural gas distribution rates be implemented effective December 17, 2016, subject to refund based on the final DPSC order.

On March 8, 2017, DPL entered into a settlement agreement with the Division of the Public Advocate, Delaware Electric Users Group and the DPSC Staff in its electric distribution rate proceeding, which provides for an increase in DPL electric distribution rates of $31.5 million based on an ROE of 9.7%. The settlement agreement also provides that the rates currently in effect, as approved by the DPSC, effective July 16, 2016 and

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

December 17, 2016 (as discussed above), will remain in effect until the date of the final DPSC order and that no refund will be required. As a result, during the first quarter of 2017, DPL established a regulatory asset of $8 million for costs incurred to achieve the merger and reversed a regulatory liability of $1 million for electric revenues that are no longer subject to refund which resulted in an increase in net income of $5 million. DPL currently expects a final order on the settlement agreement during the second quarter of 2017.

On April 6, 2017, DPL entered into a settlement agreement with the Division of the Public Advocate and the DPSC Staff in its natural gas distribution rate proceeding, which provides for an increase in DPL natural gas distribution rates of $4.9 million based on an ROE of 9.7%. The settlement agreement also provides that DPL will refund amounts in excess of the $4.9 million increase collected under the temporary rates effective July 16, 2016 and December 17, 2016 (as discussed above), and that the new rates will be effective within thirty days of DPSC approval of the settlement agreement. In the event that the final order reflects the settlement agreement, DPL does not expect the impact to be material to its financial statements. DPL currently expects a final order on the settlement agreement during the second quarter of 2017.

District of Columbia Regulatory Matters

2016 Electric Distribution Rates (Exelon, PHI and Pepco). On June 30, 2016, Pepco filed an application with the DCPSC to increase its annual electric distribution rates by $86 million, which was updated to $82 million on October 14, 2016, and further updated to approximately $77 million on February 1, 2017, based on a requested ROE of 10.6%. The DCPSC has issued a procedural schedule indicating a final decision will be issued by July 25, 2017. Any adjustments to its rates approved by the DCPSC are expected to take effect soon thereafter. Pepco cannot predict how much of the requested increase the DCPSC will approve.

On April 18, 2016, a party to a separate DCPSC proceeding filed a motion to suspend Pepco s bill stabilization adjustment (BSA), which decouples distribution revenues from utility customers from the amount of electricity delivered. On September 9, 2016, the DCPSC denied the party s motion and determined that the appropriate forum in which to determine whether the BSA continues to be just and reasonable is in Pepco s rate case proceeding. In addition, the DCPSC stated that it was putting Pepco on notice that all funds collected for the BSA from January 2015 to the issuance of a decision in the rate case proceeding are subject to refund should the DCPSC determine that such funds were not justly or reasonably collected. On November 22, 2016, following Pepco s October 7, 2016 request for reconsideration of the order, the DCPSC issued an order stating that its September 9, 2016 order was not final and confirming that issues related to the BSA, including potential remedial actions, would be addressed in Pepco s rate case. Pepco cannot predict the outcome of this matter or the impact of a refund if ordered by the DCPSC.

District of Columbia Power Line Undergrounding Initiative (Exelon, PHI and Pepco). The Electric Company Infrastructure Improvement Financing Act of 2014 (the Improvement Financing Act) was the enabling legislation for the District of Columbia Power Line Undergrounding (DC PLUG) initiative, a $1 billion project to selectively place underground some of the District of Columbia s most outage-prone power lines.

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 volumetric surcharge on the electric bills of Pepco District of Columbia customers; (ii) $375 million of the DC PLUG initiative cost is to be funded by the District of Columbia through the issuance of securitized bonds, which bonds will be repaid through a volumetric surcharge (the DDOT 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 funded 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 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.

In March 2017, the Electric Company Infrastructure Improvement Financing Amendment Act of 2017 was introduced to the Council of the District of Columbia. The proposed amendment changes a portion of the funding structure for the DC PLUG initiative from securitized bonds issued by the District to a pay-as-you-go structure with the cost imposed on the electric company and recovered by the electric company through a rate rider. This amendment would reduce the overall project authorization from $1 billion to $500 million and would provide that: (i) Pepco is to fund approximately $250 million of the estimated cost to complete the DC PLUG initiative, recovering those costs through a volumetric surcharge on the electric bills of Pepco District of Columbia customers; (ii) $188 million of the DC PLUG initiative cost would be funded through a charge collected from Pepco by the District of Columbia and Pepco would recover this charge from customers through a volumetric distribution rider; and; (iii) the remaining costs up to $62 million are to be covered by the existing capital projects program of DDOT. Pepco will not earn a return on or a return of the cost of the assets funded by the charge collected from Pepco by the District of Columbia 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 upon completion.

PHI believes that the proposed amendment addresses the assertion made by an agency of the federal government that the surcharge proposed in the Improvement Financing Act constitutes a tax on end users.

New Jersey Regulatory Matters

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

2016 Electric Distribution Rates (Exelon, PHI and ACE). On August 24, 2016, the NJBPU issued an order approving a stipulation of settlement among ACE, the New Jersey Division of Rate Counsel, NJBPU Staff and Unimin Corporation, which, among other things, provided that a determination on ACE s grid resiliency program, PowerAhead, would be separated into a phase II of the rate proceeding and decided at a later date PowerAhead includes capital investments to 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. ACE currently expects this matter to conclude in the second quarter of 2017, but cannot predict if the NJBPU will approve the PowerAhead initiative.

Update and Reconciliation of Certain Under-Recovered Balances (Exelon, PHI and ACE). On February 1, 2017, ACE submitted its 2017 annual petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE s long-term power purchase contracts with the non-utility generators and (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and ACE s uncollectible accounts. The net impact of adjusting the charges as proposed is an overall annual rate decrease of approximately $29 million (revised to approximately $32 million in April 2017, based upon an update for actuals through March 2017), including New Jersey sales and use tax. The matter is pending at the NJBPU. ACE has requested that the NJBPU place the new rates into effect by June 1, 2017. There is no assurance that NJBPU will put final rates in effect by the requested date.

New York Regulatory Matters

New York Clean Energy Standard (Exelon, Generation). On August 1, 2016, the New York Public Service Commission (NYPSC) issued an order establishing the CES, a component of which is the Tier 3 ZEC program targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet the criteria demonstrating public necessity as determined by the NYPSC. The New York State Energy Research and Development Authority (NYSERDA) will centrally procure the ZECs from eligible plants through a 12-year contract, to be administered in six two-year tranches, extending from April 1, 2017 through March 31, 2029. ZEC payments will be made to the eligible resources based upon the number of MWh produced, subject to specified caps and minimum performance requirements. The price to be paid for the ZECs under each tranche will be administratively determined using a formula based on the social cost of carbon as determined in 2016 by the federal government, subject to pricing adjustments designed to lower the ZEC price based on increase in underlying energy and capacity prices. The ZEC price for the first tranche has been set at $17.48 per MWh of production. Following the first tranche, the price will be updated bi-annually. Each Load Serving Entity (LSE) shall be required to purchase an amount of ZECs equivalent to its load ratio share of the total electric energy in the New York Control Area. Cost recovery from ratepayers shall be incorporated into the commodity charges on customer bills.

The NYPSC initially identified three plants eligible for the ZEC program: the FitzPatrick, Ginna, and Nine Mile Point nuclear facilities. As issued, the order also provided that the duration of the program beyond the first tranche was conditional upon a buyer purchasing the FitzPatrick facility and taking title prior to September 1, 2018. On November 18, 2016, the required contracts with NYSERDA were executed for Ginna and Nine Mile Point, in addition to Entergy s execution of the required contract for the FitzPatrick facility. On March 31, 2017, Generation closed on the acquisition of FitzPatrick.

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

On October 19, 2016, a coalition of fossil generation companies filed a complaint in federal district court against the NYPSC alleging that the ZEC program violates certain provisions of the U.S. Constitution; specifically that the ZEC program interferes with FERC s jurisdiction over wholesale rates and that it discriminates against out of state competitors. On December 9, 2016, Generation and CENG filed a motion to intervene in the case and to dismiss the lawsuit. The motion to intervene has been granted and the motion to dismiss is pending.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

Federal Regulatory Matters

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

	2017	
Annual Transmission Filings[(a)]	**ComEd**	**BGE**
Initial revenue requirement increase	$ 44	$ 31
Annual reconciliation (decrease) increase	(33)	3
Dedicated facilities decrease[(b)]		(8)
Total revenue requirement increase	$ 11	$ 26
Allowed return on rate base[(c)]	8.43%	7.47%
Allowed ROE[(d)]	11.50%	10.50%

85

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

Transmission Formula Rate (Exelon and PECO) On May 1, 2017, PECO filed a request with FERC seeking approval to update its transmission rates and change the manner in which PECO s transmission rate is determined from a fixed rate to a formula rate. The formula rate would be updated annually to ensure that under this rate customers pay the actual costs of providing transmission services. The formula rate filing includes a requested increase of $22 million to PECO s annual transmission revenues and a requested rate of return on common equity of 11%, inclusive of a 50 basis point adder for being a member of a regional transmission organization. PECO requested that the new transmission rate be effective as of July 2017. PECO cannot predict how much, if any, of a transmission rate increase FERC may approve or when the rate increase may go into effect.

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Complaints at FERC Seeking to Mitigate Illinois and New York Programs Providing ZECs (Exelon and Generation). PJM and NYISO capacity markets include a Minimum Offer Price Rule (MOPR) that is intended to preclude buyers from exercising buyer market power. If a resource is subjected to a MOPR, its offer is adjusted to remove the revenues it receives through a federal, state or other government-provided financial support program resulting in a higher offer that may not clear the capacity market. Currently, the MOPRs in PJM and NYISO apply only to certain new resources. Exelon has generally opposed policies that require subsidies or give preferential treatment to generation providers or technologies that do not provide superior reliability or environmental benefits, or that would threaten the reliability and value of the integrated electricity grid. Thus, Exelon has supported a MOPR as a means of minimizing the detrimental impact certain subsidized resources could have on capacity markets (such as the New Jersey (LCAPP) and Maryland (CfD) programs). However, in Exelon s view, MOPRs should not be applied to resources that receive compensation for providing superior reliability or environmental benefits.

On January 9, 2017, the Electric Power Supply Association (EPSA) filed two requests with FERC: one seeking to amend a prior complaint against PJM and another seeking expedited action on a pending NYISO compliance filing in an existing proceeding. Both filings allege that the relevant MOPR should be expanded to also apply to existing resources receiving ZEC compensation under the New York CES and Illinois ZES programs. Exelon has filed protests at FERC in response to each filing, arguing generally that ZEC payments provide compensation for an environmental attribute that is distinct from the energy and capacity sold in the FERC-jurisdictional markets, and therefore, are no different than other renewable support programs like the PTC and RPS that have generally not been subject to a MOPR. However, if successful, for Generation s facilities expected to receive ZEC compensation (Quad Cities, Ginna, Nine Mile Point and FitzPatrick), an expanded MOPR could require exclusion of ZEC compensation when bidding into future capacity auctions such that these facilities would have an increased risk of not clearing in those auctions and thus no longer receiving capacity revenues during the respective ZEC programs. Any such mitigation of these generating resources could have a material effect on Exelon s and Generation s future cash flows and results of operations. The timing of FERC s decision with respect to both proceedings is currently unknown and the outcome of these matters is currently uncertain.

Operating License Renewals (Exelon and Generation). On August 29, 2012, Generation submitted a hydroelectric license application to FERC for a 46-year license for the Conowingo Hydroelectric Project (Conowingo). In connection with Generation s efforts to obtain a water quality certification pursuant to Section 401 of the Clean Water Act with Maryland Department of the Environment (MDE) for Conowingo, Generation continues to work with MDE and other stakeholders to resolve water quality licensing issues, including: (1) water quality, (2) fish habitat, and (3) sediment. In addition, Generation continues to work with MDE and other Federal and Maryland state agencies to conduct and fund an additional sediment and nutrient monitoring study.

On April 21, 2016, Exelon and Interior executed a Settlement Agreement resolving all fish passage issues between the parties. 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 46-year life of the new license, including both capital and operating costs. The actual timing and amount of these costs are not currently fixed and may vary significantly from year to year throughout the life of the new license. Resolution of the remaining issues relating to Conowingo involving various stakeholders may have a material effect on Exelon s and Generation s results of operations and financial position through an increase in capital expenditures and operating costs. As of March 31, 2017, $29 million of direct costs associated with Conowingo licensing efforts have been capitalized. See Note 3 Regulatory Matters of the Exelon 2016 Form 10-K for additional information on Generation s operating license renewal efforts.

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

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

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

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

March 31, 2017	Exelon	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Regulatory assets								
Pension and other postretirement benefits[(a)]	$ 4,152	$	$	$	$	$	$	$
Deferred income taxes[(b)]	2,055	76	1,617	101	261	169	40	52
AMI programs	689	165	46	225	253	170	83	
Under-recovered distribution service costs[(c)]	211	211						
Debt costs	122	41	1	7	80	17	9	6
Fair value of long-term debt	797				658			
Fair value of PHI s unamortized energy contracts	1,021				1,021			
Severance	4			4				
Asset retirement obligations	116	82	22	12				
MGP remediation costs	296	271	25					
Under-recovered uncollectible accounts	63	63						
Renewable energy	285	282			3		1	2
Energy and transmission programs[(d)(e)(f)(g)(h)(i)]	71	18		19	34	6	5	23
Deferred storm costs	39			1	38	12	7	19
Electric generation-related regulatory asset	8			8				
Energy efficiency and demand response programs	596		1	269	326	241	84	1
Merger integration costs[(j)(k)]	32			8	24	11	13	
Under-recovered revenue decoupling[(l)]	76			31	45	36	9	
COPCO acquisition adjustment	7				7		7	
Recoverable Workers compensation and long-term disability cost	33				33	33		
Vacation accrual	42		17		25		15	10
Securitized stranded costs	123				123			123
CAP arrearage	11		11					
Removal costs	486				486	136	90	261
Other	46	6	8	5	27	21	4	4
Total regulatory assets	11,381	1,215	1,748	690	3,444	852	367	501
Less: current portion	1,330	183	40	191	653	173	66	94
Total non-current regulatory assets	$ 10,051	$ 1,032	$ 1,708	$ 499	$ 2,791	$ 679	$ 301	$ 407

March 31, 2017	Exelon	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Regulatory liabilities								
Other postretirement benefits	$ 48	$	$	$	$	$	$	$
Nuclear decommissioning	2,776	2,294	482					
Removal costs	1,598	1,328		136	134	17	117	
Deferred rent	39				39			
Energy efficiency and demand response programs	185	139	44		2	2		

DLC program costs	8		8					
Electric distribution tax repairs	66		66					
Gas distribution tax repairs	18		18					
Energy and transmission programs[(d)(e)(f)(g)(h)(i)]	133	38	66	2	27	7	12	8
Rate stabilization deferral	3			3				
Other	65	4	7	20	34	3	13	17
Total regulatory liabilities	4,939	3,803	691	161	236	29	142	25
Less: current portion	637	311	161	67	82	10	47	25
Total non-current regulatory liabilities	$ 4,302	$ 3,492	$ 530	$ 94	$ 154	$ 19	$ 95	$

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

December 31, 2016	Exelon	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Regulatory liabilities								
Other postretirement benefits	$ 47	$	$	$	$	$	$	$
Nuclear decommissioning	2,607	2,169	438					
Removal costs	1,601	1,324		141	136	18	118	
Deferred rent	39				39			
Energy efficiency and demand response programs	185	141	41		3	3		
DLC program costs	8		8					
Electric distribution tax repairs	76		76					
Gas distribution tax repairs	20		20					
Energy and transmission programs[d][e][f][g][h][i]	134	60	56		18	8	5	5
Other	72	4	5	19	41	2	17	20

Total regulatory liabilities	4,789	3,698	644	160	237	31	140	25
Less: current portion	602	329	127	50	79	11	43	25
Total non-current regulatory liabilities	$ 4,187	$ 3,369	$ 517	$ 110	$ 158	$ 20	$ 97	$

(a) As of March 31, 2017 and December 31, 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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(b) As of March 31, 2017, includes transmission-related regulatory assets that require FERC approval separate from the transmission formula rate of $22 million, $39 million, $31 million, $21 million and $20 million for ComEd, BGE, Pepco, DPL and ACE, respectively. As of December 31, 2016, includes transmission-related regulatory assets that require FERC approval separate from the transmission formula rate of $22 million, $38 million, $31 million, $20 million and $19 million for ComEd, BGE, Pepco, DPL and ACE, respectively.

(c) As of March 31, 2017, ComEd s regulatory asset of $211 million was comprised of $158 million for the 2015 2017 annual reconciliations and $53 million related to significant one-time events including $17 million of deferred storm costs, $10 million of Constellation and PHI merger and integration related costs and $26 million of smart meter related costs. As of December 31, 2016, ComEd s regulatory asset of $188 million was comprised of $134 million for the 2015 and 2016 annual reconciliations and $54 million related to significant one-time events, including $20 million of deferred storm costs and $11 million of Constellation and PHI merger and integration related costs, and $23 million of smart meter related costs. ComEd s 2015 annual reconciliation regulatory asset included a reduction of $8 million related to a ComEd-proposed refund to customers for the impact of changing its OSHA recordable rate for 2014 and 2015. See Note 4 Merger, Acquisitions, and Dispositions of the Exelon 2016 Form 10-K for further information.

(d) As of March 31, 2017, ComEd s regulatory asset of $18 million included $10 million associated with transmission costs recoverable through its FERC approved formula rate and $8 million of Constellation merger and integration costs to be recovered upon FERC approval. As of March 31, 2017, ComEd s regulatory liability of $38 million included $6 million related to over-recovered energy costs and $32 million associated with revenues received for renewable energy requirements. As of December 31, 2016, ComEd s regulatory asset of $23 million included $15 million associated with transmission costs recoverable through its FERC approved formula rate and $8 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2016, ComEd s regulatory liability of $60 million included $30 million related to over-recovered energy costs and $30 million associated with revenues received for renewable energy requirements.

(e) As of March 31, 2017, PECO s regulatory liability of $66 million included $41 million related to over-recovered costs under the DSP program, $13 million related to the over-recovered natural gas costs under the PGC, $10 million related to over-recovered non-bypassable transmission service charges and $2 million related to over-recovered electric transmission costs. As of December 31, 2016, PECO s regulatory liability of $56 million included $34 million related to over-recovered costs under the DSP program, $10 million related to over-recovered non-bypassable transmission service charges, $8 million related to the over-recovered natural gas costs under the PGC and $4 million related to the over-recovered electric transmission costs.

(f) As of March 31, 2017, BGE s regulatory asset of $19 million included $3 million of costs associated with transmission costs recoverable through its FERC approved formula rate, $13 million related to under-recovered electric energy costs, and $3 million of abandonment costs to be recovered upon FERC approval. As of March 31, 2017, BGE s regulatory liability consisted of $2 million related to over-recovered natural gas costs. As of December 31, 2016, BGE s regulatory asset of $38 million included $4 million of costs associated with transmission costs recoverable through its FERC approved formula rate, $28 million related to under-recovered electric energy costs, $3 million of abandonment costs to be recovered upon FERC approval, and $3 million of under-recovered natural gas costs.

(g) As of March 31, 2017, Pepco s regulatory asset of $6 million included $2 million of transmission costs recoverable through its FERC approved formula rate and $4 million of under-recovered electric energy costs. As of March 31, 2017, Pepco s regulatory liability of $7 million included $2 million of over-recovered transmission costs and $5 million of over-recovered electric energy costs. As of December 31, 2016, Pepco s regulatory asset of $6 million related to under-recovered electric energy costs. As of December 31, 2016, Pepco s regulatory liability of $8 million included $5 million of over-recovered transmission costs and $3 million of over-recovered electric energy costs.

(h) As of March 31, 2017, DPL s regulatory asset of $5 million related to under-recovered electric energy costs. As of March 31, 2017, DPL s regulatory liability of $12 million included $9 million of over-recovered electric energy costs, $1 million of over-recovered transmission costs, and $2 million of over-recovered gas cost. As of December 31, 2016, DPL s regulatory asset of $5 million included $1 million of transmission costs recoverable through its FERC approved formula rate and $4 million of under-recovered electric energy costs. As of December 31, 2016, DPL s regulatory liability of $5 million included $2 million of over-recovered electric energy costs and $3 million of over-recovered transmission costs.

(i) As of March 31, 2017, ACE s regulatory asset of $23 million included $10 million of transmission costs recoverable through its FERC approved formula rate and $13 million of under-recovered electric energy costs. As of March 31, 2017, ACE s regulatory liability of $8 million included $2 million of over-recovered transmission costs and $6 million of over-

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

recovered electric energy costs. As of December 31, 2016, ACE s regulatory asset of $17 million included $6 million of transmission costs recoverable through its FERC approved formula rate and $11 million of under-recovered electric energy costs. As of December 31, 2016, ACE s regulatory liability of $5 million included $4 million of over-recovered transmission costs and $1 million of over-recovered electric energy costs.

(j) As of March 31, 2017, BGE s regulatory asset of $8 million included $6 million of previously incurred PHI acquisition costs as authorized by the June 2016 rate case order.

(k) As of March 31, 2017 and December 31, 2016, Pepco s regulatory asset of $11 million represents previously incurred PHI acquisition costs authorized for recovery by the November 2016 Maryland distribution rate case order. As of March 31, 2017, DPL s regulatory asset of $13 million represents previously incurred PHI acquisition costs, including $5 million authorized for recovery by the February 2017 Maryland distribution rate case order and $8 million expected to be recovered in electric and gas distribution rates in the Delaware service territory. As of December 31, 2016, DPL s regulatory asset of $4 million represents previously incurred PHI acquisition costs expected to be recovered in distribution rates in the Maryland service territory.

(l) Represents the electric and natural gas distribution costs recoverable from customers under BGE s decoupling mechanism. As of March 31, 2017, BGE had a regulatory asset of $25 million related to under-recovered electric revenue decoupling and $6 million related to under-recovered natural gas revenue decoupling. As of December 31, 2016, BGE had a regulatory asset of $2 million related to under-recovered natural gas revenue decoupling and $1 million related to under-recovered electric revenue decoupling.

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

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

	Exelon	ComEd[(a)]	PECO	BGE[(b)]	PHI	Pepco[(c)]	DPL[(c)]	ACE
March 31, 2017	$ 71	$ 5	$	$ 56	$ 10	$ 6	$ 4	$

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

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

(b) BGE s authorized amounts capitalized for ratemaking purposes related to earnings on shareholders investment on its AMI Programs.

(c) Pepco s and DPL s authorized amounts capitalized for ratemaking purposes related to earnings on shareholders investment on their respective AMI Programs and Energy Efficiency and Demand Response Programs. The earnings on energy efficiency are on Pepco DC and DPL DE programs only.

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

ComEd, PECO, BGE, Pepco, DPL and ACE are required, under separate legislation and regulations in Illinois, Pennsylvania, Maryland, District of Columbia and New Jersey, to purchase certain receivables from retail electric and natural gas suppliers that participate in the utilities consolidated billing. ComEd, BGE, Pepco and DPL purchase receivables at a discount to recover primarily uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and is permitted to recover uncollectible accounts expense, including those from Third Party Suppliers, from customers through distribution rates. ACE purchases receivables at face value. ACE recovers all uncollectible accounts expense, including those from Third Party Suppliers, through the Societal Benefits Charge (SBC) rider, which includes uncollectible accounts expense as a component. The SBC is filed annually with the NJBPU. Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 provi information about the purchased receivables of those companies as of March 31, 2017 and December 31, 2016.

As of March 31, 2017	Exelon	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Purchased receivables[b]	$ 305	$ 85	$ 72	$ 59	$ 89	$ 58	$ 10	$ 21
Allowance for uncollectible accounts[a]	(36)	(14)	(7)	(4)	(11)	(6)	(2)	(3)
Purchased receivables, net	$ 269	$ 71	$ 65	$ 55	$ 78	$ 52	$ 8	$ 18

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

(a) For ComEd, BGE, Pepco and DPL, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing tariff.

(b) Pepco s electric POR program in Maryland included a discount on purchased receivables ranging from 0% to 2% depending on customer class, 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)

Generation evaluates long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. During the first quarter of 2016, significant changes in Generation s intended use of the Upstream oil and gas assets, developments with nonrecourse debt held by its upstream subsidiary CEU Holdings, LLC (as described in Note 14 Debt and Credit Agreements of the Exelon 2016 Form 10-K) and continued declines in both production volumes and commodity prices suggested that the carrying value may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of its Upstream properties were less than their carrying values. As a result, a pre-tax impairment charge of $119 million was recorded in March 2016 within Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. On June 16, 2016, Generation initiated the sales process of its Upstream business by executing a forbearance agreement with the lenders of the nonrecourse debt. An additional pre-tax impairment charge of $15 million was recorded in September 2016 within Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income due to further declines in fair value. In December 2016, Generation sold substantially all of the Upstream Assets. See Note 4 Merger, Acquisitions, and Dispositions of the Exelon 2016 Form 10-K for further information.

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).

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

7. Early Nuclear Plant Retirements (Exelon and Generation)

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation s nuclear plants. Factors that will continue to affect the economic value of Generation s nuclear plants include, but are not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions to ensure nuclear plants are fairly compensated for their carbon-free emissions, and the impact of potential rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules. In 2015 and 2016, Generation identified the Clinton, Quad Cities, Ginna, Nine Mile Point, and Three Mile Island (TMI) nuclear plants as having the greatest risk of early retirement based on economic valuation and other factors. PSEG has also recently made public similar financial challenges facing its New Jersey nuclear plants including Salem, of which Generation owns a 42.59% ownership interest. As previously disclosed, Exelon and Generation have committed to cease operation of the Oyster Creek nuclear plant by the end of 2019.

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

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

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

(a) Reflected incremental accelerated depreciation of plant assets, including any ARC, for the period June 2, 2016, through December 6, 2016.
(b) Primarily included materials and supplies inventory reserve adjustments, employee related costs and construction work-in-progress (CWIP) impairments.
(c) For Quad Cities based on the regulatory agreement with the Illinois Commerce Commission, decommissioning-related activities are offset within Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The offset results in an equal adjustment to the noncurrent payables to ComEd at Generation and an adjustment to the regulatory liabilities at ComEd. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability.

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

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

The TMI nuclear plant 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, the second consecutive year that TMI failed to clear the PJM base residual capacity auction. The plant is currently committed to operate through May 2019. TMI will be offered into the May 2017 PJM capacity auction for the 2020-2021 planning year, however the plant faces continued economic challenges and Exelon and Generation are exploring all options to return it to profitability, including the potential for a legislative solution in Pennsylvania similar to that passed in Illinois.

The following table provides the balance sheet amounts as of March 31, 2017 for significant assets and liabilities associated with TMI, the plant currently considered by management to be at the greatest risk of early retirement due to current economic valuations and other factors.

(in millions)	**TMI**
Asset Balances	
Materials and supplies inventory	$ 40
Nuclear fuel inventory, net	72
Completed plant, net	1,000
Construction work in progress	40
Liability Balances	
Asset retirement obligation	(572)
NRC License Renewal Term	2034

The precise timing of an early retirement date for any nuclear plant, and the resulting financial statement impacts, may be affected by a number of factors, including the status of potential regulatory or legislative solutions, results of any transmission system reliability study assessments, the nature of any co-owner

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

requirements and stipulations, and decommissioning trust fund requirements, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity or other obligations, where applicable, and just prior to its next scheduled nuclear refueling outage.

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

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of the Registrants short-term liabilities, long-term debt, SNF obligation, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of March 31, 2017 and December 31, 2016:

Exelon

	March 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 2,048	$	$ 2,048	$	$ 2,048
Long-term debt (including amounts due within one year)[a]	34,689	1,135	32,562	1,962	35,659
Long-term debt to financing trusts[b]	641			677	677
SNF obligation	1,136		813		813

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

Generation

	March 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 717	$	$ 717	$	$ 717
Long-term debt (including amounts due within one year)[a]	9,979		8,200	1,671	9,871
SNF obligation	1,136		813		813

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

SNF obligation	1,024	732	732

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

ComEd

	March 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 365	$	$ 365	$	$ 365
Long-term debt (including amounts due within one year)[a]	7,035		7,615		7,615
Long-term debt to financing trusts[b]	205			218	218

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

PECO

	March 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 2,580	$	$ 2,806	$	$ 2,806
Long-term debt to financing trusts	184			193	193

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

BGE

	March 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 95	$	$ 95	$	$ 95
Long-term debt (including amounts due within one year)[a]	2,323		2,501		2,501
Long-term debt to financing trusts[b]	252			266	266

	December 31, 2016				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total

Short-term liabilities	$ 45	$	$ 45	$	$ 45
Long-term debt (including amounts due within one year)[(a)]	2,322		2,467		2,467
Long-term debt to financing trusts[(b)]	252			260	260

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

PHI (Successor)

	March 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 167	$	$ 167	$	$ 167
Long-term debt (including amounts due within one year)[a]	5,860		5,510	291	5,801

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

Pepco

	March 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 167	$	$ 167	$	$ 167
Long-term debt (including amounts due within one year)[a]	2,350		2,804	9	2,813

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

DPL

	March 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 1,326	$	$ 1,374	$	$ 1,374

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

ACE

	March 31, 2017				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[(a)]	$ 1,145	$	$ 989	$ 282	$ 1,271

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

(a) Includes unamortized debt issuance costs which are not fair valued of $199 million, $67 million, $45 million, $15 million, $14 million, $2 million, $29 million, $11 million, and $5 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, as of March 31, 2017. Includes unamortized debt issuance costs of $200 million, $64 million, $46 million, $15 million, $15 million, $2 million, $30 million, $11 million, and $6 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, as of December 31, 2016.

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

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

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

Level 1 quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to liquidate as of the reporting date.

Level 2 inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.

Level 3 unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Transfers in and out of levels are recognized as of the end of the reporting period when the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Additionally, there were no material transfers between Level 1 and Level 2 during the three months ended March 31, 2017 for cash equivalents, nuclear decommissioning trust fund investments, pledged assets for Zion Station decommissioning, Rabbi trust investments, and deferred compensation obligations. For derivative contracts, transfers into Level 2 from Level 3 generally occur when the contract tenor becomes more observable and due to changes in market liquidity or assumptions for certain commodity contracts.

Generation and Exelon

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

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 March 31, 2017 and December 31, 2016:

	Generation					Exelon				
As of March 31, 2017	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Assets										
Cash equivalents[a]	$ 135	$	$	$	$ 135	$ 342	$	$	$	$ 342
NDT fund investments										
Cash equivalents[b]	160	21			181	160	21			181
Equities	4,113	505	1	2,089	6,708	4,113	505	1	2,089	6,708
Fixed income										
Corporate debt		1,749	255		2,004		1,749	255		2,004
U.S. Treasury and agencies	1,516	35			1,551	1,516	35			1,551
Foreign governments		57			57		57			57
State and municipal debt		241			241		241			241
Other[c]		52		484	536		52		484	536
Fixed income subtotal	1,516	2,134	255	484	4,389	1,516	2,134	255	484	4,389
Middle market lending			427	64	491			427	64	491
Private equity				158	158				158	158
Real estate				427	427				427	427
NDT fund investments subtotal[d]	5,789	2,660	683	3,222	12,354	5,789	2,660	683	3,222	12,354
Pledged assets for Zion Station decommissioning										
Cash equivalents	21				21	21				21
Equities		1			1		1			1
Fixed income U.S. Treasury and agencies	8	1			9	8	1			9
Middle market lending			20	44	64			20	44	64
Pledged assets for Zion Station decommissioning subtotal[e]	29	2	20	44	95	29	2	20	44	95
Rabbi trust investments										
Cash equivalents	7				7	80				80
Mutual funds	20				20	53				53
Fixed income							15			15
Life insurance contracts		20			20		66	20		86
Rabbi trust investments subtotal	27	20			47	133	81	20		234
Commodity derivative assets										
Economic hedges	749	2,993	1,631		5,373	751	2,993	1,631		5,375
Proprietary trading	5	50	25		80	5	50	25		80
Effect of netting and allocation of collateral[f][g]	(639)	(2,575)	(873)		(4,087)	(641)	(2,575)	(873)		(4,089)

Commodity derivative assets subtotal	115	468	783		1,366	115	468	783		1,366
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments							12			12
Economic hedges		22			22		22			22
Proprietary trading	3	1			4	3	1			4
Effect of netting and allocation of collateral	(4)	(14)			(18)	(4)	(14)			(18)
Interest rate and foreign currency derivative assets subtotal	(1)	9			8	(1)	21			20
Other investments			40		40			40		40
Total assets	6,094	3,159	1,526	3,266	14,045	6,407	3,232	1,546	3,266	14,451

101

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Generation					Exelon				
As of March 31, 2017	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Liabilities										
Commodity derivative liabilities										
Economic hedges	(787)	(2,855)	(1,167)		(4,809)	(787)	(2,855)	(1,449)		(5,091)
Proprietary trading	(6)	(49)	(22)		(77)	(6)	(49)	(22)		(77)
Effect of netting and allocation of collateral[f][g]	714	2,846	971		4,531	714	2,846	971		4,531
Commodity derivative liabilities subtotal	(79)	(58)	(218)		(355)	(79)	(58)	(500)		(637)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments		(1)			(1)		(1)			(1)
Economic hedges		(25)			(25)		(25)			(25)
Proprietary trading	(3)				(3)	(3)				(3)
Effect of netting and allocation of collateral	4	14			18	4	14			18
Interest rate and foreign currency derivative liabilities subtotal	1	(12)			(11)	1	(12)			(11)
Deferred compensation obligation		(35)			(35)		(135)			(135)
Total liabilities	(78)	(105)	(218)		(401)	(78)	(205)	(500)		(783)
Total net assets	$ 6,016	$ 3,054	$ 1,308	$ 3,266	$ 13,644	$ 6,329	$ 3,027	$ 1,046	$ 3,266	$ 13,668

	Generation					Exelon				
As of December 31, 2016	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Assets										
Cash equivalents[a]	$ 39	$	$	$	$ 39	$ 373	$	$	$	$ 373
NDT fund investments										
Cash equivalents[b]	110	19			129	110	19			129
Equities	3,551	452		2,011	6,014	3,551	452		2,011	6,014
Fixed income										
Corporate debt		1,554	250		1,804		1,554	250		1,804
U.S. Treasury and agencies	1,291	29			1,320	1,291	29			1,320
Foreign governments		37			37		37			37
State and municipal debt		264			264		264			264
Other[c]		59		493	552		59		493	552
Fixed income subtotal	1,291	1,943	250	493	3,977	1,291	1,943	250	493	3,977
Middle market lending			427	71	498			427	71	498
Private equity				148	148				148	148
Real estate				326	326				326	326

NDT fund investments subtotal[(d)]	4,952	2,414	677	3,049	11,092	4,952	2,414	677	3,049	11,092
Pledged assets for Zion Station decommissioning										
Cash equivalents	11				11	11				11
Equities		2			2		2			2
Fixed Income U.S. Treasury and agencies	16	1			17	16	1			17
Middle market lending			19	64	83			19	64	83
Pledged assets for Zion Station decommissioning subtotal[(e)]	27	3	19	64	113	27	3	19	64	113
Rabbi trust investments										
Cash equivalents	2				2	74				74
Mutual funds	19				19	50				50
Fixed income							16			16
Life insurance contracts		18			18		64	20		84
Rabbi trust investments subtotal	21	18			39	124	80	20		224

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

(a)

Generation excludes cash of $267 million and $252 million at March 31, 2017 and December 31, 2016 and restricted cash of $138 million and $157 million at March 31, 2017 and December 31, 2016. Exelon excludes cash of $381 million and $360 million at March 31, 2017 and December 31, 2016 and restricted cash of $165 million and $180 million at March 31, 2017 and December 31, 2016 and includes long term restricted cash of $25 million at March 31, 2017 and December 31, 2016, which is reported in other deferred debits on the balance sheet.

(b) Includes less than $1 million and $29 million of cash received from outstanding repurchase agreements at March 31, 2017 and December 31, 2016, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (d) below.

(c) Includes derivative instruments of $(1) million and $(2) million, which have a total notional amount of $886 million and $933 million at March 31, 2017 and December 31, 2016, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company s exposure to credit or market loss.

(d) Excludes net assets (liabilities) of $8 million and $(31) million at March 31, 2017 and December 31, 2016, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(e) Excludes net assets of less than $1 million at March 31, 2017 and December 31, 2016. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(f) Collateral posted/(received) from counterparties totaled $75 million, $271 million and $98 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of March 31, 2017. Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled $71 million, $197 million and $61 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2016.
(g) Of the collateral posted/(received), $14 million represents variation margin on the exchanges as of March 31, 2017. Of the collateral posted/(received), $(158) million represents variation margin on the exchanges as of December 31, 2016.

ComEd, PECO and BGE

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

	ComEd				PECO				BGE			
As of March 31, 2017	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents[(a)]	$	$	$	$	$ 5	$	$	$ 5	$ 45	$	$	$ 45
Rabbi trust investments												
Mutual funds					7			7	5			5
Life insurance contracts						10		10				
Rabbi trust investments subtotal					7	10		17	5			5
Total assets					12	10		22	50			50
Liabilities												
Deferred compensation obligation		(8)		(8)		(11)		(11)		(4)		(4)
Mark-to-market derivative liabilities[(b)]			(282)	(282)								
Total liabilities		(8)	(282)	(290)		(11)		(11)		(4)		(4)
Total net assets (liabilities)	$	$ (8)	$ (282)	$ (290)	$ 12	$ (1)	$	$ 11	$ 50	$ (4)	$	$ 46

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

(a) ComEd excludes cash of $31 million and $36 million at March 31, 2017 and December 31, 2016 and restricted cash of $3 million and $2 million at March 31, 2017 and December 31, 2016. PECO excludes cash of $27 million and $22 million at March 31, 2017 and December 31, 2016. BGE excludes cash of $11 million and $13 million at March 31, 2017 and December 31, 2016 and includes long term restricted cash of $2 million at March 31, 2017 and December 31, 2016, which is reported in other deferred debits on the balance sheet.

(b) The Level 3 balance consists of the current and noncurrent liability of $19 million and $263 million, respectively, at March 31, 2017, and $19 million and $239 million, respectively, at December 31, 2016, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

PHI, Pepco, DPL and ACE

The following tables present assets and liabilities measured and recorded at fair value on PHI s, Pepco s, DPL s and ACE s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2017 and December 31, 2016:

	Successor As of March 31, 2017				*Successor* As of December 31, 2016			
PHI	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets								
Cash equivalents[(a)]	$ 154	$	$	$ 154	$ 217	$	$	$ 217
Mark-to-market derivative assets[(b)]					2			2
Effect of netting and allocation of collateral					(2)			(2)
Mark-to-market derivative assets subtotal								
Rabbi trust investments								
Cash equivalents	74			74	73			73
Fixed income		15		15		16		16
Life insurance contracts		23	20	43		22	20	42
Rabbi trust investments subtotal	74	38	20	132	73	38	20	131
Total assets	228	38	20	286	290	38	20	348
Liabilities								
Deferred compensation obligation		(25)		(25)		(28)		(28)
Total liabilities		(25)		(25)		(28)		(28)
Total net assets	$ 228	$ 13	$ 20	$ 261	$ 290	$ 10	$ 20	$ 320

	Pepco				**DPL**				**ACE**			
As of March 31, 2017	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents[(a)]	$ 33	$	$	$ 33	$ 39	$	$	$ 39	$ 80	$	$	$ 80
Rabbi trust investments												
Cash equivalents	43			43	1			1				
Fixed income		15		15								
Life insurance contracts		23	20	43								
Rabbi trust investments subtotal	43	38	20	101	1			1				
Total assets	76	38	20	134	40			40	80			80

Liabilities												
Deferred compensation obligation		(4)		(4)		(1)		(1)				
Total liabilities		(4)		(4)		(1)		(1)				
Total net assets (liabilities)	$ 76	$ 34	$ 20	$ 130	$ 40	$ (1)	$	$ 39	$ 80	$	$	$ 80

106

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

(a) PHI excludes cash of $19 million and $19 million at March 31, 2017 and December 31, 2016 and includes long term restricted cash of $23 million and $23 million at March 31, 2017 and December 31, 2016 which is reported in other deferred debits on the balance sheet. Pepco excludes cash of $8 million and $9 million at March 31, 2017 and December 31, 2016. DPL excludes cash of $5 million and $4 million at March 31, 2017 and December 31, 2016. ACE excludes cash of $4 million and $3 million at March 31, 2017 and December 31, 2016 and includes long term restricted cash of $23 million and $23 million at March 31, 2017 and December 31, 2016 which is reported in other deferred debits on the balance sheet.

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

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 fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2017 and 2016:

	Generation					ComEd	*Successor* PHI		Exelon
Three Months Ended March 31, 2017	**NDT Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total Generation**	**Mark-to-Market Derivatives[(a)]**	**Life Insurance Contracts**	**Eliminated in Consolidation**	**Total**
Balance as of December 31, 2016	$ 677	$ 19	$ 493	$ 42	$ 1,231	$ (258)	$ 20	$	$ 993
Total realized / unrealized gains (losses)									
Included in net income	3		(43)[(b)]	1	(39)		1		(38)
Included in noncurrent payables to affiliates	9				9			(9)	
Included in regulatory assets/liabilities						(24)		9	(15)
Change in collateral			38		38				38
Purchases, sales, issuances and settlements									
Purchases	17	1	69	2	89				89
Sales			(2)		(2)				(2)
Issuances							(1)		(1)
Settlements	(23)				(23)				(23)
Transfers into Level 3			(1)		(1)				(1)
Transfers out of Level 3			11	(5)	6				6
Balance as of March 31, 2017	$ 683	$ 20	$ 565	$ 40	$ 1,308	$ (282)	$ 20	$	$ 1,046
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of March 31, 2017	$ 2	$	$ 59	$	$ 61	$	$ 1	$	$ 62

(a) Includes $30 million of decreases in fair value and an increase for realized losses due to settlements of $6 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2017.

(b) Includes a reduction for the reclassification of $102 million of realized gains due to the settlement of derivative contracts for the three months ended March 31, 2017.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Three Months Ended March 31, 2016	Generation: NDT Fund Investments	Generation: Pledged Assets for Zion Station Decommissioning	Generation: Mark-to-Market Derivatives	Generation: Other Investments	Generation: Total Generation	ComEd: Mark-to-Market Derivatives[a]	*Successor* PHI[c]: Life Insurance Contracts	Eliminated in Consolidation	Exelon: Total
Balance as of December 31, 2015	$ 670	$ 22	$ 1,051	$ 33	$ 1,776	$ (247)	$	$	$ 1,529
Included due to merger							20		20
Total realized / unrealized gains (losses)									
Included in net income	2		(6)[b]		(4)				(4)
Included in noncurrent payables to affiliates	4				4			(4)	
Included in payable for Zion Station decommissioning		2			2				2
Included in regulatory assets						(18)		4	(14)
Change in collateral			(50)		(50)				(50)
Purchases, sales, issuances and settlements									
Purchases	34	1	59	3	97				97
Sales			(2)		(2)				(2)
Settlements	(26)				(26)				(26)
Transfers into Level 3			2		2				2
Transfers out of Level 3			(7)		(7)				(7)
Balance as of March 31, 2016	$ 684	$ 25	$ 1,047	$ 36	$ 1,792	$ (265)	$ 20	$	$ 1,547
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of March 31, 2016	$ 1	$	$ 219	$	$ 220	$	$	$	$ 220

(a) Includes $25 million of decreases in fair value and an increase for realized losses due to settlements of $7 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2016.

(b) Includes a reduction for the reclassification of $225 million of realized gains due to the settlement of derivative contracts recorded in results of operations for the three months ended March 31, 2016.

(c) Successor period represents activity from March 24, 2016 through March 31, 2016. See tables below for PHI s predecessor periods, as well as activity for Pepco for the three months ended March 31, 2017 and 2016.

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

109

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Pepco	**Life Insurance Contracts Three Months Ended March 31, 2017**	**2016**
Beginning Balance	$ 20	$ 19
Total realized / unrealized gains (losses)		
Included in net income	1	1
Purchases, sales, issuances and settlements		
Issuances	(1)	
Ending Balance	$ 20	$ 20
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities for the period	$ 1	$ 1

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2017 and 2016:

	Generation			*Successor* **PHI**	**Exelon**		
	Operating Revenues	**Purchased Power and Fuel**	**Other, net[(a)]**	**Other, net[(a)]**	**Operating Revenues**	**Purchased Power and Fuel**	**Other, net[(a)]**
Total gains (losses) included in net income for the three months ended March 31, 2017	88	(131)	3	1	88	(131)	4
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended March 31, 2017	140	(81)	2	1	140	(81)	3

	Generation			**Exelon**		
	Operating Revenues	**Purchased Power and Fuel**	**Other, net[(a)]**	**Operating Revenues**	**Purchased Power and Fuel**	**Other, net[(a)]**
Total gains (losses) included in net income for the three months ended March 31, 2016	49	(55)	2	49	(55)	2
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended March 31, 2016	254	(35)	1	254	(35)	1

	Predecessor **PHI January 1, 2016 to March 23, 2016**	**Pepco Three Months Ended March 31, 2017**	**Three Months Ended March 31, 2016**
		Other, net	
Total gains (losses)included in net income	$ (17)	$ 1	$ 1
	1	1	1

Change in the unrealized gains (losses) relating to assets and liabilities held

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Valuation Techniques Used to Determine Fair Value

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

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

Preferred Stock Derivative (PHI). In connection with entering into the PHI Merger Agreement, PHI entered into a Subscription Agreement with Exelon dated April 29, 2014, pursuant to which PHI issued to Exelon shares of Preferred stock. The Preferred stock contained embedded features requiring separate accounting consideration to reflect the potential value to PHI that any issued and outstanding Preferred stock could be called and redeemed at a nominal par value upon a termination of the merger agreement under certain circumstances due to the failure to obtain required regulatory approvals. The embedded call and redemption features on the shares of the Preferred stock in the event of such a termination were separately accounted for as derivatives. These Preferred stock derivatives were valued quarterly using quantitative and qualitative factors, including management s assessment of the likelihood of a Regulatory Termination and therefore, were categorized in Level 3 in the fair value hierarchy. As a result of the PHI Merger, the PHI Preferred stock derivative was reduced to zero as of March 23, 2016. The write-off was charged to Other, net on the PHI Consolidated Statement of Operations and Comprehensive Income.

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

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

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

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

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

Middle market lending are investments in loans or managed funds which lend to private companies. Generation elected the fair value option for its investments in certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models and income models. Investments in loans are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Managed funds are valued using NAV or its equivalent as a practical expedient, and therefore, are not classified within the fair value hierarchy. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

Private equity and real estate investments include those in limited partnerships that invest in operating companies and real estate holding companies that are not publicly traded on a stock exchange, such as, leveraged buyouts, growth capital, venture capital, distressed investments, investments in natural resources, and direct investments in pools of real estate properties. The fair value of private equity and real estate investments is determined using NAV or its equivalent as a practical expedient, and therefore, are not classified within the fair value hierarchy. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date. Private equity and real estate valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows, market based comparable data, and independent appraisals from sources with professional qualifications. These valuation inputs are unobservable.

As of March 31, 2017, Generation has outstanding commitments to invest in middle market lending, private equity investments and real estate investments of approximately \$290 million, \$120 million, and \$107 million, respectively. These commitments will be funded by Generation s existing nuclear decommissioning trust funds.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Concentrations of Credit Risk. Generation evaluated its NDT portfolios for the existence of significant concentrations of credit risk as of March 31, 2017. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of March 31, 2017, there were no significant concentrations (generally defined as greater than 10 percent) of risk in Generation s NDT assets.

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

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

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

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market s expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 9 Derivative Financial Instruments for further discussion on mark-to-market derivatives.

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

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

Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd, PHI, Pepco 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.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 $0.40 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3.

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 9 Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.

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

Type of trade	Fair Value at March 31, 2017	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives Economic Hedges (Exelon and Generation)[(a)(c)]	$ 464	Discounted Cash Flow	Forward power price	$8 $130
			Forward gas price	$1.92 $9.87
		Option Model	Volatility percentage	13% 112%
Mark-to-market derivatives Proprietary trading (Exelon and Generation)[(a)(c)]	$ 3	Discounted Cash Flow	Forward power price	$15 $67
Mark-to-market derivatives (Exelon and ComEd)	$ (282)	Discounted Cash Flow	Forward heat rate[(b)]	8x 9x
			Marketability reserve	3% 8%
			Renewable factor	88% 121%

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(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 $98 million as of March 31, 2017.

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

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract s delivery.
(c) The fair values do not include cash collateral posted on level three positions of $61 million as of December 31, 2016.

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

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). For middle market lending and certain corporate debt securities investments, the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on discounting the forecasted cash flows, market-based comparable data, credit and liquidity factors, as well as other factors that may impact value. Significant judgment is required

116

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

in the application of discounts or premiums applied for factors such as size, marketability, credit risk and relative performance.

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Generation gains an understanding of the fund managers inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations.

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

9. Derivative Financial Instruments (All Registrants)

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

Commodity Price Risk (All Registrants)

To the extent the amount of energy Generation produces differs from the amount of energy it has contracted to sell, Exelon and Generation are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. Each of the Registrants employ established policies and procedures to manage their risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and energy-related products. The Registrants believe these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedge and fair value hedge. For Generation, all derivative economic hedges related to commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. The Registrants have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. Generation has also entered into bilateral long-term contractual obligations for sales of energy to load-serving entities, including electric utilities, municipalities, electric cooperatives and retail load aggregators, as well as contractual obligations to deliver energy to market participants who primarily focus on the resale of energy products for delivery. These non-derivative contracts are accounted for primarily under the accrual method of accounting. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation s energy marketing portfolio but represent a small portion of Generation s overall energy marketing activities.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 March 31, 2017, the proportion of expected generation hedged for the major reportable segments is 97%-100%, 60%-63% and 30%-33% for 2017, 2018 and 2019, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation s sales to ComEd, PECO, and BGE to serve their retail load.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 3 Regulatory Matters of the Exelon 2016 Form 10-K for additional information.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

PECO s natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply reliability at the least cost. PECO s reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO s natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2016 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2016 PGC settlement, PECO is required to lock in (i.e. economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO s gas-hedging program is designed to cover about 25% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO s financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

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

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

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

DPL has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and the DPSC. The SOS rates charged recover DPL s wholesale power supply costs. In Delaware, DPL is also entitled to recover a Reasonable Allowance for Retail Margin (RARM). The RARM includes a fixed annual margin of approximately $2.75 million, plus an incremental cost component and a cash working capital allowance. In Maryland, DPL charges an administrative fee intended to allow it to recover its administrative costs. DPL locks in fixed prices for all of its SOS requirements through full requirements

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

contracts. DPL s price risk related to electric supply procurement is limited. Certain of DPL s full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

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

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

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon s RMC. The proprietary trading activities, which included settled physical sales volumes of 1,850 GWhs and 1,220 GWhs for the three months ended March 31, 2017 and 2016, respectively, are a complement to Generation s energy marketing portfolio but represent a small portion of Generation s revenue from energy marketing activities. ComEd, PECO, BGE, PHI, Pepco, DPL and ACE do not enter into derivatives for proprietary trading purposes.

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

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 March 31, 2017, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding, and Exelon and Generation had $657 million of notional amounts of floating-to-fixed hedges outstanding. 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 $2 million decrease in Exelon Consolidated pre-tax income for the three months ended March 31, 2017. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. Below is a summary of the interest rate and foreign exchange hedge balances as of March 31, 2017:

	Generation					Exelon Corporate	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading[(a)]	Collateral and Netting[(b)]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$	$ 15	$ 3	$ (13)	$ 5	$	$ 5
Mark-to-market derivative assets (noncurrent assets)		7	1	(5)	3	12	15
Total mark-to-market derivative assets		22	4	(18)	8	12	20
Mark-to-market derivative liabilities (current liabilities)	(1)	(17)	(2)	13	(7)		(7)
Mark-to-market derivative liabilities (noncurrent liabilities)		(8)	(1)	5	(4)		(4)
Total mark-to-market derivative liabilities	(1)	(25)	(3)	18	(11)		(11)
Total mark-to-market derivative net assets (liabilities)	$ (1)	$ (3)	$ 1	$	$ (3)	$ 12	$ 9

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

(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases, Exelon and Generation may have other offsetting counterparty exposures subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

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 interest rate and foreign exchange hedge balances recorded by the Registrants as of December 31, 2016:

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

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

(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases, Exelon and Generation may have other offsetting counterparty exposures subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

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

	Three Months Ended March 31,			
Income Statement Location	2017	2016	2017	2016
	Gain (loss) on Swaps		Gain (loss) on Borrowings	

Exelon	Interest expense	$ (4)	$ 17	$ 8	$ (15)

At March 31, 2017, Exelon had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $800 million, with a derivative asset of $12 million. At December 31, 2016, Exelon had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $800 million, with a derivative asset of $16 million. During the three months ended March 31, 2017 and 2016, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $4 million gain and a $2 million gain, respectively.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

During the first quarter of 2014, EGR, a subsidiary of Generation, entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 14 Debt and Credit Agreements of the Exelon 2016 Form 10-K for additional information regarding the financing. The swaps have a notional amount of $164 million as of March 31, 2017 and expire in 2020. The swaps are designated as cash flow hedges. At March 31, 2017, the subsidiary had a $1 million derivative liability related to the swaps.

During the three months ended March 31, 2017 and 2016, the impact on the results of operations as a result of ineffectiveness from cash flow hedges in continuing designated hedge relationships was immaterial.

Economic Hedges. During the third quarter of 2014, EGTP, a subsidiary of Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with the long-term borrowing. See Note 14 Debt and Credit Agreements of the Exelon 2016 Form 10-K for additional information regarding the financing. The swaps have a notional amount of $494 million as of March 31, 2017 and expire in 2019. The swap was designated as a cash flow hedge in the fourth quarter of 2014. During the first quarter of 2017, the swap was de-designated. At March 31, 2017, the subsidiary had a $7 million derivative liability related to the swap.

During the third quarter of 2011, Sacramento PV Energy, a subsidiary of Generation entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 14 Debt and Credit Agreements of the Exelon 2016 Form 10-K for additional information regarding the financing. During the first quarter of 2016, upon the termination of debt, Generation terminated the swaps. The total notional amount of the swaps 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 2016 Form 10-K for additional information regarding the financing. During the first quarter of 2016, upon the termination of debt, Generation terminated the swap. The total notional amount of the swap was $24 million. No gain or loss was recognized as a result of the termination of the swap.

At March 31, 2017, Generation had immaterial notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $73 million in

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

notional amounts of foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

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

Fair value accounting guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. Generation s use of cash collateral is generally unrestricted, unless Generation is downgraded below investment grade (i.e., to BB+ or Ba1). In the table below, Generation s energy related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including margin on exchange positions, is aggregated in the collateral and netting column. As of both March 31, 2017 and December 31, 2016, $8 million of cash collateral held 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.

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 March 31, 2017:

	Generation				ComEd	DPL			*Successor* PHI	Exelon
Derivatives	**Economic Hedges**	**Proprietary Trading**	**Collateral and Netting[(a)(e)]**	**Subtotal[(b)]**	**Economic Hedges[(c)]**	**Economic Hedges[(d)]**	**Collateral and Netting[(a)]**	**Subtotal**	**Subtotal**	**Total Derivatives**
Mark-to-market derivative assets (current assets)	$ 3,398	$ 56	$ (2,612)	$ 842	$	$	$	$	$	$ 842
Mark-to-market derivative assets (noncurrent assets)	1,975	24	(1,475)	524						524
Total mark-to-market derivative assets	5,373	80	(4,087)	1,366						1,366
Mark-to-market derivative liabilities (current liabilities)	(3,029)	(49)	2,876	(202)	(19)					(221)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,780)	(28)	1,655	(153)	(263)					(416)
Total mark-to-market derivative liabilities	(4,809)	(77)	4,531	(355)	(282)					(637)
Total mark-to-market derivative net assets (liabilities)	$ 564	$ 3	$ 444	$ 1,011	$ (282)	$	$	$	$	$ 729

(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 $128 million and $77 million, respectively, and current and noncurrent liabilities are shown net of collateral of $136 million and $103 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $444 million at March 31, 2017.

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

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

(e) Of the collateral posted/(received), $14 million represents variation margin on the exchanges.

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, 2016:

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

(a) Exelon, Generation, PHI and DPL net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, and letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $100 million and $72 million, respectively, and current and noncurrent liabilities are shown net of collateral of $95 million and $62 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $329 million at December 31, 2016.

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

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

(e) Of the collateral posted/(received), $(158) million represents variation margin on the exchanges.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Cash Flow Hedges (Exelon and Generation). The tables below provide the activity of OCI related to cash flow hedges for the three months ended March 31, 2017 and 2016, containing information about the changes in the fair value of cash flow hedges and the reclassification from Accumulated OCI into results of operations. The amounts reclassified from OCI, when combined with the impacts of the hedged transactions, result in the ultimate recognition of net revenues or expenses at the contractual price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended March 31, 2017	**Income Statement Location**	**Total Cash Flow Hedges**	**Total Cash Flow Hedges**
Accumulated OCI derivative loss at December 31, 2016		$ (19)	$ (17)
Effective portion of changes in fair value		2	2
Reclassifications from AOCI to net income	Interest Expense	4[(a)]	4[(a)]
Accumulated OCI derivative loss at March 31, 2017		$ (13)	$ (11)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended March 31, 2016	**Income Statement Location**	**Total Cash Flow Hedges**	**Total Cash Flow Hedges**
Accumulated OCI derivative loss at December 31, 2015		$ (21)	$ (19)
Effective portion of changes in fair value		(8)	(10)
Reclassifications from AOCI to net income	Interest Expense	3[(b)]	3[(b)]
Accumulated OCI derivative loss at March 31, 2016		$ (26)	$ (26)

(a) Amount is net of related income tax expense of $3 million for the three months ended March 31, 2017.
(b) Amount is net of related income tax expense of $2 million for the three months ended March 31, 2016.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, physical forward sales and purchases, but for which the fair value or cash flow hedge elections were not made. Additionally, Generation enters into interest rate derivative contracts and foreign exchange currency swaps (treasury) to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars. For the three months ended March 31, 2017 and 2016, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in Operating revenues or Purchased power and fuel expense, or Interest expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in Net fair value changes related to derivatives in Exelon s and Generation s Consolidated Statements of Cash Flows. In the tables below, Change in fair value represents the change in fair value of the derivative contracts held at the reporting date. The Reclassification to realized generally represents the recognized change in fair value that was reclassified from unrealized to realized when the transaction to which the derivative relates occurs.

		Generation		Exelon
Three Months Ended March 31, 2017	**Operating Revenues**	**Purchased Power and Fuel**	**Total**	**Total**
Change in fair value of commodity positions	$ 93	$ (135)	$ (42)	$ (42)
Reclassification to realized of commodity positions	(47)	42	(5)	(5)
Net commodity mark-to-market gains (losses)	46	(93)	(47)	(47)
Change in fair value of treasury positions	(1)		(1)	(1)
Reclassification to realized of treasury positions	(1)		(1)	(1)
Net treasury mark-to-market gains (losses)	(2)		(2)	(2)
Net mark-to-market gains (losses)	$ 44	$ (93)	$ (49)	$ (49)

		Generation		Exelon
Three Months Ended March 31, 2016	**Operating Revenues**	**Purchased Power and Fuel**	**Total**	**Total**
Change in fair value of commodity positions	$ 279	$ (127)	$ 152	$ 152
Reclassification to realized of commodity positions	(211)	167	(44)	(44)
Net commodity mark-to-market gains (losses)	68	40	108	108
Change in fair value of treasury positions	(3)		(3)	(3)
Reclassification to realized of treasury positions	(2)		(2)	(2)
Net treasury mark-to-market gains (losses)	(5)		(5)	(5)
Net mark-to-market gains (losses)	$ 63	$ 40	$ 103	$ 103

Proprietary Trading Activities (Exelon and Generation). For the three months ended March 31, 2017 and 2016, Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) before income taxes relating to mark-to-market activity on commodity derivative instruments entered into for proprietary trading purposes and interest rate and foreign exchange derivative contracts to hedge risk associated with the interest rate and foreign exchange components of underlying commodity positions. Gains and losses associated with proprietary trading are reported as operating revenues in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income and are included in Net fair value changes related to derivatives in Exelon s and

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Generation s Consolidated Statements of Cash Flows. In the tables below, Change in fair value represents the change in fair value of the derivative contracts held at the reporting date. The Reclassification to realized represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Change in fair value of commodity positions	$	$ 7
Reclassification to realized of commodity positions	(1)	(3)
Net commodity mark-to-market gains (losses)	(1)	4
Change in fair value of treasury positions		(2)
Reclassification to realized of treasury positions	(1)	1
Net treasury mark-to-market gains (losses)	(1)	(1)
Total net mark-to-market gains (losses)	$ (2)	$ 3

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 March 31, 2017. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below exclude credit risk exposure from individual retail counterparties, Nuclear fuel procurement contracts and exposure through RTOs, ISOs, NYMEX, ICE, NASDAQ, NGX and Nodal commodity exchanges. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of $13 million, $31 million,$24 million, $40 million, $13 million, and $7 million as of March 31, 2017, respectively.

Rating as of March 31, 2017	Total Exposure Before Credit Collateral	Credit Collateral(a)	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 964	$ 16	$ 948	1	$ 313
Non-investment grade	75	3	72		
No external ratings					
Internally rated investment grade	324		324		
Internally rated non-investment grade	127	14	113		
Total	$ 1,490	$ 33	$ 1,457	1	$ 313

Net Credit Exposure by Type of Counterparty	As of March 31, 2017
Financial institutions	$ 101
Investor-owned utilities, marketers, power producers	600
Energy cooperatives and municipalities	663
Other	93
Total	$ 1,457

(a) As of March 31, 2017, credit collateral held from counterparties where Generation had credit exposure included $23 million of cash and $10 million of letters of credit. The credit collateral does not include non-liquid collateral.

ComEd s power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd s net credit exposure. As of March 31, 2017, ComEd s net credit exposure to suppliers was approximately $1 million.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 Regulatory Matters of the Exelon 2016 Form 10-K for additional information.

PECO s supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier s performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier s lowest credit rating from the major credit rating agencies and the supplier s tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 March 31, 2017, PECO had no material net credit exposure to suppliers.

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

PECO s natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO s counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of March 31, 2017, PECO had no material credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 Regulatory Matters of the Exelon 2016 Form 10-K for additional information.

BGE s full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier s performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier s lowest credit rating from the major credit rating agencies and the supplier s tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier s unsecured credit limit. The unsecured credit used by the suppliers represents BGE s net credit exposure. The seller s credit exposure is calculated each business day. As of March 31, 2017, BGE had no net credit exposure to suppliers.

BGE s regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE s recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers demands, which are not covered by the gas cost adjustment clause. At March 31, 2017, BGE had credit exposure of $3 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 March 31, 2017, Pepco s, DPL s and ACE s net credit exposures to suppliers were immaterial.

Pepco is permitted to recover its costs of procuring energy through the MDPSC-approved and DCPSC-approved procurement tariffs. DPL is permitted to recover its costs of procuring energy through the MDPSC-approved and DPSC-approved procurement tariffs. ACE is permitted to recover its costs of procuring energy through the NJBPU-approved procurement tariffs. Pepco s, DPL s and ACE s counterparty credit risks are mitigated by their ability to recover realized energy costs through customer rates. See Note 3 Regulatory Matters of the Exelon 2016 Form 10-K for additional information.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

DPL s natural gas procurement plan is reviewed and approved annually on a prospective basis by the DPSC. DPL s counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the GCR, which allows DPL to adjust rates annually to reflect realized natural gas prices. To the extent that the fair value of the transactions in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. Exchange-traded contracts are required to be fully collateralized without regard to the credit rating of the holder. As of March 31, 2017, DPL had no credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

Collateral and Contingent-Related Features (All Registrants)

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

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

Credit-Risk Related Contingent Feature	March 31, 2017	December 31, 2016
Gross Fair Value of Derivative Contracts Containing this Feature[(a)]	$ (994)	$ (960)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements[(b)]	712	627
Net Fair Value of Derivative Contracts Containing This Feature[(c)]	$ (282)	$ (333)

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

Generation had cash collateral posted of $471 million and letters of credit posted of $273 million and cash collateral held of $35 million and letters of credit held of $32 million as of March 31, 2017 for external counterparties with derivative positions. Generation had cash collateral posted of $347 million and letters of credit posted of $284 million and cash collateral held of $24 million and letters of credit held of $28 million at December 31, 2016 for external counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e., to

132

BB+ by S&P or Ba1 by Moody s), Generation would have been required to post additional collateral of $1.8 billion and $1.9 billion as of March 31, 2017 and December 31, 2016, respectively. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation s and Exelon s interest rate swaps contain provisions that, in the event of a merger, if Generation s debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of March 31, 2017, Generation s swaps were in a liability position with a fair value of $3 million and Exelon s swaps were in an asset position, with a fair value of $9 million.

See Note 26 Segment Information of the Exelon 2016 Form 10-K for further information regarding the letters of credit supporting the cash collateral.

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of ComEd s standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of March 31, 2017, ComEd held approximately $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 March 31, 2017, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. If ComEd lost its investment grade credit rating as of March 31, 2017, it would have been required to post approximately $10 million of collateral to its counterparties. See Note 3 Regulatory Matters of the Exelon 2016 Form 10-K for additional information.

PECO s natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO s credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of March 31, 2017, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of March 31, 2017, PECO could have been required to post approximately $27 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 March 31, 2017, BGE was not required to post collateral for any of these agreements. If

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

BGE lost its investment grade credit rating as of March 31, 2017, BGE could have been required to post approximately $47 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 March 31, 2017, DPL could have been required to post an additional amount of approximately $11 million of collateral to its natural gas counterparties.

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

10. Debt and Credit Agreements (All Registrants)

Short-Term Borrowings

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

Commercial Paper

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

Commercial Paper Borrowings	**March 31, 2017**	**December 31, 2016**
Exelon Corporate	$ 204	$
Generation	579	620
ComEd	365	
PECO		
BGE	95	45
PHI Corporate		
Pepco	167	23

Short-Term Loan Agreements

On January 13, 2016, PHI entered into a $500 million term loan agreement, which was amended on March 28, 2016. The net proceeds of the loan were used to repay PHI s outstanding commercial paper, and for

134

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

Credit Agreements

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

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Long-Term Debt

Issuance of Long-Term Debt

During the three months ended March 31, 2017, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Energy Efficiency Project Financing	3.72%	April 30, 2018	$ 1	Funding to install energy conservation measures for the Smithsonian Zoo project
Generation	Energy Efficiency Project Financing	2.61%	September 30, 2018	$ 1	Funding to install energy conservation measures for the Pensacola project
Generation	Energy Efficiency Project Financing	3.90%	January 31, 2018	$ 6	Funding to install energy conservation measures for the Naval Station Great Lakes project
Generation	Albany Green Energy Project Financing	LIBOR + 1.25%	November 17, 2017	$ 13	Albany Green Energy biomass generation development
Generation	Senior Notes	2.95%	January 15, 2020	$ 250	Repay outstanding commercial paper obligations and for general corporate purposes.
Generation	Senior Notes	3.40%	March 15, 2022	$ 500	Repay outstanding commercial paper obligations and for general corporate purposes.
Pepco	Energy Efficiency Project Financing	3.30%	December 15, 2017	$ 1	Funding to install energy conservation measures for the DOE Germantown project

EGTP Nonrecourse Debt

In September 2014, EGTP, an indirect subsidiary of Exelon and Generation, issued $675 million aggregate principal amount of a nonrecourse senior secured term loan. The net proceeds were distributed to Generation for general business purposes. The loan is scheduled to mature on September 18, 2021. The term loan bears interest at a variable rate equal to LIBOR plus 4.75%, subject to a 1% LIBOR floor with interest payable quarterly. As of March 31, 2017, $658 million was outstanding. As part of the agreement, a revolving credit facility was established for the amount of $20 million available through, and scheduled to mature on September 18, 2019. In addition to the financing, EGTP entered into various interest rate swaps with an initial notional amount of approximately $505 million at an interest rate of 2.34% to hedge a portion of the interest rate exposure in connection with this financing, as required by the debt covenants. See Note 9 Derivative Financial Instruments for additional information regarding interest rate swaps. See Note 20 Subsequent Events for additional information regarding EGTP and the associated nonrecourse debt.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Junior Subordinated Notes

In June 2014, Exelon issued $1.15 billion of junior subordinated notes in the form of 23 million equity units at a stated amount of $50.00 per unit. Each equity unit represented an undivided beneficial ownership interest in Exelon s $1.15 billion of 2.50% junior subordinated notes due in 2024 (2024 notes) and a forward equity purchase contract. As contemplated in the June 2014 equity unit structure, in April 2017, Exelon completed the remarketing of the 2024 notes into $1.15 billion of 3.497% junior subordinated notes due in 2022 (Remarketing). Exelon conducted the Remarketing on behalf of the holders of equity units and did not directly receive any proceeds therefrom. Instead, the former holders of the 2024 notes may use debt remarketing proceeds towards settling the forward equity purchase contract with Exelon on June 1, 2017. Exelon will receive $1.15 billion upon settlement on June 1, 2017, of the forward equity purchase contract. Exelon currently expects the number of equity shares to be issued to range from 26 million to 33 million dependent on Exelon s stock price at the time of settlement pursuant to the equity unit terms. Until settlement of the equity purchase contract, earnings per share dilution resulting from the equity units is being determined under the treasury stock method.

For the three months ended March 31, 2017 and 2016, contract payments of $11 million related to the Contract Payment Obligation were included within Retirements of long-term debt in Exelon s Consolidated Statements of Cash Flows.

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 March 31, 2017								
									Successor
	Exelon	**Generation**	**ComEd**	**PECO**	**BGE**	**Pepco**	**DPL**	**ACE**	**PHI**
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	0.9	1.0	4.9	0.1	5.2	4.6	5.3	5.6	4.9
Qualified nuclear decommissioning trust fund income	3.4	7.6							
Amortization of investment tax credit, including deferred taxes on basis difference	(0.4)	(0.7)	(0.2)	(0.1)	(0.1)	(0.1)	(0.3)	(0.4)	(0.2)
Plant basis differences	(2.4)		(0.2)	(13.2)	(0.9)	(5.8)	(1.9)	(3.4)	(3.8)
Production tax credits and other credits	(0.6)	(1.4)							
Noncontrolling interests	(0.1)	(0.3)							
Merger expenses[(a)]	(11.4)	(3.3)				(34.2)	(21.9)	(167.1)	(42.4)
Fitzpatrick bargain purchase gain	(6.6)	(14.5)							
Other		(0.1)		0.3	(0.2)	0.5		(3.0)	(0.4)
Effective income tax rate	17.8%	23.3%	39.5%	22.1%	39.0%	0.0%	16.2%	(133.3)%	(6.9)%

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Three Months Ended March 31, 2016								*Successor* March 24, 2016 to March 31, 2016	*Predecessor* January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco[(b)]	DPL[(b)]	ACE[(b)]	PHI[(b)]	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[(c)]	(1.1)	3.7	5.1	1.0	5.2	(2.5)	(2.7)	5.9	5.4	11.9
Qualified nuclear decommissioning trust fund income	5.6	4.2								
Amortization of investment tax credit, including deferred taxes on basis difference	(1.6)	(1.0)	(0.3)	(0.1)	(0.1)		0.1	0.2		(0.9)
Plant basis differences	(5.5)		(0.1)	(9.3)	(0.6)	2.8	0.7	0.6		(13.5)
Production tax credits and other credits	(5.1)	(3.9)								
Noncontrolling interests	0.5	0.3								
Merger expenses	33.6					(16.5)	(22.1)	(17.0)	(15.1)	11.1
Other	(2.0)	(1.6)	0.4	(0.9)			0.1	0.1	0.2	3.6
Effective income tax rate	59.4%	36.7%	40.1%	25.7%	39.5%	18.8%	11.1%	24.8%	25.5%	47.2%

(a) Includes a remeasurement of uncertain federal and state income tax positions, see below.
(b) Pepco, DPL and ACE recognized a loss before income taxes for the three months ended March 31, 2016, and PHI recognized a loss before income taxes for the period of March 24, 2016, through March 31, 2016. As a result, positive percentages represent an income tax benefit for the periods presented.
(c) Includes a remeasurement of uncertain state income tax positions for Pepco and DPL.

Accounting for Uncertainty in Income Taxes

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

	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
March 31, 2017	$ 769	$ 470	$ (12)	$	$ 120	$ 112	$ 59	$ 21	$

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

Exelon established a liability for an uncertain tax position associated with the tax deductibility of certain merger commitments incurred by Exelon in connection with the acquisitions of Constellation in 2012 and PHI in 2016. In the first quarter 2017, as a part of its examination of Exelon s return, the IRS National Office issued guidance concurring with Exelon s position that the merger commitments were deductible. As a result, Exelon, Generation, PHI, Pepco, DPL, and ACE decreased their liability for unrecognized tax benefits by $146 million, $19 million,

$59 million, $21 million, $16 million, and $22 million, respectively, as of March 31, 2017, resulting in a benefit to Income taxes on Exelon s, Generation s, PHI s, Pepco s, DPL s and ACE s Consolidated Statements of Operations and Comprehensive Income and corresponding decreases in their effective tax rates.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 March 31, 2017, Exelon and ComEd have approximately $76 million and $(12) million, respectively, of unrecognized state income tax benefits that could significantly decrease and increase within the 12 months after the reporting date due to a final resolution of the like-kind exchange litigation described below. The recognition of these unrecognized tax benefits would decrease Exelon s effective tax rate and increase ComEd s effective tax rate.

Settlement of Income Tax Audits

As of March 31, 2017, Exelon, Generation, BGE, PHI, Pepco, and DPL have approximately $257 million, $57 million, $120 million, $80 million, $59 million, and $21 million of unrecognized federal and state tax benefits that could significantly decrease within the 12 months after the reporting date as a result of completing audits and potential settlements. Of the above unrecognized tax benefits, Exelon and Generation have $50 million that, if recognized, would decrease the effective tax rate. The unrecognized tax benefits related to BGE, DPL, and a portion of Pepco, if recognized, may be included in future regulated base rates and that portion would have no impact to the effective tax rate.

Other Income Tax Matters

Like-Kind Exchange (Exelon and ComEd)

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

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

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

On September 19, 2016, the Tax Court rejected Exelon s position in the case and ruled that Exelon was not entitled to defer gain on the transaction. In addition, contrary to Exelon s evaluation that the penalty was unwarranted, the Tax Court ruled that Exelon is liable for the penalty and interest due on the asserted penalty. Exelon expects to timely appeal this decision to the U.S. Court of Appeals for the Seventh Circuit in 2017.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

In the first quarter of 2013, Exelon concluded that it was no longer more likely than not that the like-kind exchange position would be sustained and recorded charges to earnings representing the amount of interest expense (after-tax) and incremental state income tax expense that would be payable in the event Exelon is unsuccessful in litigation. Prior to the Tax Court s decision, however, Exelon did not believe it was likely a penalty would be assessed based on applicable case law and the facts of the transaction. As a result, no charge had been recorded for the penalty or for after-tax interest on the penalty. While it has strong arguments on appeal with respect to both the merits and the penalty, Exelon has determined that, pursuant to accounting standards, it is no longer more likely than not to avoid ultimate imposition of the penalty. As a result, in the third quarter of 2016, Exelon and ComEd recorded a charge to earnings of approximately $106 million and $86 million, respectively, of penalty and approximately $94 million and $64 million, respectively, of after-tax interest. Exelon and ComEd recorded the penalty and pre-tax interest due on the asserted penalty to Other, net and Interest expense, net, respectively, on their Consolidated Statements of Operations. Consistent with Exelon s agreement to continue to hold ComEd harmless from any unfavorable impact on its equity, ComEd recorded on its Consolidated Balance Sheets as of September 30, 2016, a $150 million receivable and non-cash equity contributions from Exelon. In addition, while further adjustments may be required, Exelon currently estimates that its income tax expense may decrease by as much as $50 million and ComEd s income tax expense may increase by as much as $20 million resulting from the IRS s completion of its calculation of tax, penalties, and interest in the second quarter of 2017.

In order to appeal the decision, Exelon is required to pay the tax, penalties and interest at the time Exelon files its appeal (expected in the third quarter of 2017). While the final calculation of tax, penalties and interest has not yet been finalized by the IRS, Exelon estimates that a payment of approximately $1.3 billion related to the like-kind exchange will be due, including $300 million from ComEd, in the third quarter of 2017. While Exelon will receive a tax benefit of approximately $350 million associated with the deduction for the interest, Exelon currently has a net operating loss carryforward and thus does not expect to realize the cash benefit until 2018. After taking into account these interest deduction tax benefits, the total estimated net cash outflow for the like-kind exchange is approximately $950 million, of which approximately $300 million is attributable to ComEd after giving consideration to Exelon s agreement to hold ComEd harmless from any unfavorable impacts of after-tax interest or penalty amounts on ComEd s equity. Upon a final appellate decision, which could take up to several years, Exelon expects to receive approximately $80 million related to final interest computations.

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

As of March 31, 2017, ComEd has a total receivable from Exelon pursuant to the hold harmless agreement of $345 million, which is included in Current Receivables from Affiliates on ComEd s Consolidated Balance Sheet. Under the agreement, Exelon will settle this receivable with ComEd no later than the time that the payments related to the like-kind exchange are due to the IRS, currently anticipated in the third quarter of 2017. Exelon will not seek recovery from ComEd customers for any interest or penalty payment amounts associated with the like-kind exchange tax position.

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

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

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

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

12. Nuclear Decommissioning (Exelon and Generation)

Nuclear Decommissioning Asset Retirement Obligations

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

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

Nuclear decommissioning ARO at December 31, 2016[a]	$ 8,734
Acquisition of FitzPatrick	417
Accretion expense	109
Costs incurred to decommission retired plants	(1)
Nuclear decommissioning ARO at March 31, 2017[a][b]	$ 9,259

(a) Includes $11 million and $10 million for the current portion of the ARO at March 31, 2017 and December 31, 2016, respectively, which is included in Other current liabilities on Exelon s and Generation s Consolidated Balance Sheets.
(b) Includes the fair value of the FitzPatrick ARO liability as of March 31, 2017, the date of the acquisition. See Note 4 Mergers, Acquisitions and Dispositions.

During the three months ended March 31, 2017, Generation s nuclear ARO increased by approximately $525 million. The increase is largely driven by the acquisition of FitzPatrick. The fair value of FitzPatrick s assets and liabilities, including the ARO, was determined based on significant estimates and assumptions that are judgmental in nature. The fair value of the ARO is considered an initial estimate and will be updated with inputs from a third party engineering firm with corresponding adjustments recorded by the end of 2017. For additional details on the acquisition of FitzPatrick, see Note 4 Mergers, Acquisitions and Dispositions.

Nuclear Decommissioning Trust Fund Investments

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

141

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

At March 31, 2017 and December 31, 2016, Exelon and Generation had NDT fund investments totaling $12,362 million and $11,061 million, respectively. The increase is primarily driven by the acquisition of FitzPatrick.

The following table provides unrealized gains on NDT funds for the three months ended March 31, 2017 and 2016:

		Exelon and Generation Three Months Ended March 31,	
		2017	**2016**
Net unrealized gains on decommissioning trust funds	Regulatory Agreement Units[a]	$ 222	$ 79
Net unrealized gains on decommissioning trust funds	Non-Regulatory Agreement Units[b][c]	166	52

(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 and $2 million of net unrealized gains (losses) related to the Zion Station pledged assets for the three months ended March 31, 2017 and 2016 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 27 Related Party Transactions of the Exelon 2016 Form 10-K for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

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 2016 Form 10-K for information regarding the specific treatment of assets, including NDT funds, and decommissioning liabilities transferred in the transaction.

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to Pledged assets for Zion Station decommissioning within Generation s and Exelon s Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a Payable for Zion Station decommissioning in Generation s and Exelon s Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, are recorded as a change in the Payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Generation has retained its obligation for the SNF. Following ZionSolutions completion of its contractual obligations and transfer of the NRC license to Generation, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal, and will complete all remaining decommissioning activities associated with the SNF dry storage facility. Generation has a liability of approximately $112 million which is included within the nuclear decommissioning ARO at March 31, 2017. Generation also has retained NDT assets to fund its obligation to maintain the SNF at Zion Station until transfer to the DOE and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payables to ZionSolutions, and withdrawals by ZionSolutions at March 31, 2017 and December 31, 2016:

	Exelon and Generation	
	March 31, 2017	December 31, 2016
Carrying value of Zion Station pledged assets	$ 95	$ 113
Payable to Zion Solutions[(a)]	88	104
Current portion of payable to Zion Solutions[(b)]	85	90
Cumulative withdrawals by Zion Solutions to pay decommissioning costs[(c)]	895	878

(a) Excludes a liability recorded within Exelon s and Generation s Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT funds. The NDT funds will be utilized to satisfy the tax obligations as gains and losses are realized.
(b) Included in Other current liabilities within Exelon s and Generation s Consolidated Balance Sheets.
(c) Includes project expenses to decommission Zion Station and estimated tax payments on Zion Station NDT fund earnings.

NRC Minimum Funding Requirements

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

Generation filed its biennial decommissioning funding status report with the NRC on March 30, 2017 for all units except for Zion Station which is included in a separate report to the NRC submitted by EnergySolutions

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

13. Retirement Benefits (All Registrants)

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

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

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

Defined Benefit Pension and Other Postretirement Benefits

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

The majority of the 2017 pension benefit cost for Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 4.04%. The majority of the 2017 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.58% for funded plans and a discount rate of 4.04%.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

A portion of the net periodic benefit cost for all plans is capitalized within the Consolidated Balance Sheets. The following tables present the components of Exelon s net periodic benefit costs, prior to capitalization, for the three months ended March 31, 2017 and 2016 and PHI s net periodic benefit costs, prior to capitalization, for the predecessor period of January 1, 2016 to March 23, 2016.

	Pension Benefits Three Months Ended March 31,		Other Postretirement Benefits Three Months Ended March 31,	
	2017	2016[(a)]	2017	2016[(a)]
Components of net periodic benefit cost:				
Service cost	$ 95	$ 78	$ 26	$ 26
Interest cost	210	190	45	43
Expected return on assets	(299)	(263)	(41)	(38)
Amortization of:				
Prior service cost (benefit)		3	(47)	(44)
Actuarial loss	152	127	16	14
Net periodic benefit cost	$ 158	$ 135	$ (1)	$ 1

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The amounts below represent Exelon s, Generation s, ComEd s, PECO s, BGE s, PHI s, Pepco s, DPL s, ACE s, BSC s and PHISCO s allocated p of the pension and postretirement benefit plan costs, which were included in Property, plant and equipment within the respective Consolidated Balance Sheets and Operating and maintenance expense within the Consolidated Statement of Operations and Comprehensive Income during the three months ended March 31, 2017 and 2016 and PHI s for the predecessor and successor periods of January 1, 2016 to March 23, 2016 and March 24, 2016 to March 31, 2016, respectively.

Pension and Other Postretirement Benefit Costs	Three Months Ended March 31, 2017	2016
Exelon	$ 157	$ 136
Generation	54	54
ComEd	44	41
PECO	7	8
BGE	16	16
BSC(a)	12	14
Pepco(b)	7	8
DPL(b)	3	5
ACE(b)	3	4
PHISCO(a)(b)	11	9

Pension and Other Postretirement Benefit Costs	*Successor* March 24, 2016 to March 31, 2016	*Predecessor* January 1, 2016 to March 23, 2016
PHI	$ 3	$ 23

(a) These amounts primarily represent amounts billed to Exelon s subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO, BGE, PHI, Pepco, DPL or ACE amounts above.
(b) Pepco s, DPL s, ACE s and PHISCO s pension and postretirement benefit costs for the three months ended March 31, 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.

Defined Contribution Savings Plans

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the three months ended March 31, 2017 and 2016:

Savings Plan Matching Contributions	Three Months Ended March 31, 2017	2016
Exelon	$ 30	$ 26
Generation	14	12
ComEd	7	6
PECO	2	2
BGE	2	1

BSC[a]	2	5
Pepco[b]	1	1
DPL[b]	1	1
PHISCO[a][b]	1	1

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Savings Plan Matching Contributions	*Successor* March 24, 2016 to March 31, 2016	*Predecessor* January 1, 2016 to March 23, 2016
PHI	$	$ 3

(a) These amounts primarily represent amounts billed to Exelon and PHI s subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO, BGE, Pepco and DPL amounts above.
(b) Pepco s, DPL s and PHISCO s matching contributions for the three months ended March 31, 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 three months ended March 31, 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.

For the three months ended March 31, 2017 and 2016, Exelon, Generation, and ComEd recorded the following severance costs (benefits) associated with these ongoing severance benefits within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income.

	Exelon	Generation[(a)]	ComEd[(a)]
Three Months Ended			
March 31, 2017	$ 4	$ 3	$ 1
March 31, 2016	2	2	

(a) The amounts above for Generation include $1 million for amounts billed by BSC through intercompany allocations for both the three months ended March 31, 2017 and 2016. Amounts billed by BSC to ComEd were immaterial.

Cost Management Program-Related Severance

In August 2015, Exelon announced a cost management program focused on cost savings at BSC and Generation, including the elimination of approximately 500 positions. These actions are in response to the continuing economic challenges confronting all parts of Exelon s business and industry, necessitating continued focus on cost management through enhanced efficiency and productivity. Exelon expects that approximately 250 corporate support positions in BSC and approximately 250 positions located throughout Generation will be eliminated.

For the three months ended March 31, 2017 and 2016, the Registrants recorded the following severance costs related to the cost management program within Operating and maintenance expense in their Consolidated

147

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Statements of Operations and Comprehensive Income, pursuant to the authoritative guidance for ongoing severance plans:

	Exelon	Generation	ComEd	PECO	BGE
Three Months Ended					
March 31, 2017[(a)]	$ (1)	$ (1)	$	$	$
March 31, 2016[(b)]	$ 17	$ 12	$ 3	$ 1	$ 1

(a) Amounts billed by BSC through intercompany allocations for the three months ended March 31, 2017 were immaterial.
(b) The amounts above for Generation, ComEd, PECO and BGE include $7 million, $3 million, $1 million and $1 million, respectively, for amounts billed by BSC through intercompany allocations for the three months ended March 31, 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 months ended March 31, 2017, the PHI merger severance costs were immaterial. For the three months ended March 31, 2016, the Registrants recorded the following severance costs associated with the identified job reductions within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income, pursuant to the authoritative guidance for ongoing severance plans:

	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Three Months Ended March 31, 2016									
Severance benefits[(a)]	$ 52	$ 10	$ 2	$ 1	$ 1	$ 37	$ 18	$ 11	$ 8

(a) The amounts above for Generation, ComEd, PECO, BGE, Pepco, DPL and ACE include $9 million, $2 million, $1 million, $1 million, $18 million, $11 million and $8 million, respectively, for amounts billed by BSC and/or PHISCO through intercompany allocations for the three months ended March 31, 2016.

Severance Liability

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

Severance Liability	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Balance at December 31, 2016	$ 88	$ 36	$ 3	$	$	$ 29	$	$	$
Severance charges[(a)]	3	1							
Payments	(10)	(3)				(5)			
Balance at March 31, 2017	$ 81	$ 34	$ 3	$	$	$ 24	$	$	$

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

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 three months ended March 31, 2017 and 2016:

Three Months Ended March 31, 2017	Gains and (losses) on Cash Flow Hedges	Unrealized Gains and (losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon[a]						
Beginning balance	$ (17)	$ 4	$ (2,610)	$ (30)	$ (7)	$ (2,660)
OCI before reclassifications	2	1	(59)	1	5	(50)
Amounts reclassified from AOCI[b]	4		36			40
Net current-period OCI	6	1	(23)	1	5	(10)
Ending balance	$ (11)	$ 5	$ (2,633)	$ (29)	$ (2)	$ (2,670)
Generation[a]						
Beginning balance	$ (19)	$ 2	$	$ (30)	$ (7)	$ (54)
OCI before reclassifications	2			1	6	9
Amounts reclassified from AOCI[b]	4					4
Net current-period OCI	6			1	6	13
Ending balance	$ (13)	$ 2	$	$ (29)	$ (1)	$ (41)
PECO[a]						
Beginning balance	$	$ 1	$	$	$	$ 1
OCI before reclassifications						
Amounts reclassified from AOCI[b]						
Net current-period OCI						
Ending balance	$	$ 1	$	$	$	$ 1

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Three Months Ended March 31, 2016	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
Exelon[a]						
Beginning balance	$ (19)	$ 3	$ (2,565)	$ (40)	$ (3)	$ (2,624)
OCI before reclassifications	(10)	(1)	(1)	6	(3)	(9)
Amounts reclassified from AOCI[b]	3		34			37
Net current-period OCI	(7)	(1)	33	6	(3)	28
Ending balance	$ (26)	$ 2	$ (2,532)	$ (34)	$ (6)	$ (2,596)
Generation[a]						
Beginning balance	$ (21)	$ 1	$	$ (40)	$ (3)	$ (63)
OCI before reclassifications	(8)			6	(2)	(4)
Amounts reclassified from AOCI[b]	3					3
Net current-period OCI	(5)			6	(2)	(1)
Ending balance	$ (26)	$ 1	$	$ (34)	$ (5)	$ (64)
PECO[a]						
Beginning balance	$	$ 1	$	$	$	$ 1
OCI before reclassifications						
Amounts reclassified from AOCI[b]						
Net current-period OCI						
Ending balance	$	$ 1	$	$	$	$ 1
PHI Predecessor[a]						
Beginning balance January 1, 2016	$ (8)	$	$ (28)	$	$	$ (36)
OCI before reclassifications						
Amounts reclassified from AOCI[b]			1			1
Net current-period OCI			1			1
Ending balance March 23, 2016[c]	$ (8)	$	$ (27)	$	$	$ (35)

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

ComEd, PECO, BGE, Pepco, DPL and ACE did not have any reclassifications out of AOCI to Net income during the three months ended March 31, 2017 and 2016. The following tables present amounts reclassified out of AOCI to Net income for Exelon, Generation and PHI during the three months ended March 31, 2017 and 2016.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Three Months Ended March 31, 2017

Details about AOCI components	Items reclassified out of AOCI[a] Exelon	Generation	Affected line item in the Statement of Operations and Comprehensive Income
Gains and (losses) on cash flow hedges			
Other cash flow hedges	$ (7)	$ (7)	Interest expense
Total before tax	(7)	(7)	
Tax benefit	3	3	
Net of tax	$ (4)	$ (4)	Comprehensive income
Amortization of pension and other postretirement benefit plan items			
Prior service costs[b]	$ 23	$	
Actuarial losses[b]	(81)		
Total before tax	(58)		
Tax benefit	22		
Net of tax	$ (36)	$	
Total Reclassifications	$ (40)	$ (4)	Comprehensive income

Three Months Ended March 31, 2016

Details about AOCI components	Items reclassified out of AOCI[a] Exelon	Generation	*Predecessor* PHI	Affected line item in the Statement of Operations and Comprehensive Income
Gains and (losses) on cash flow hedges				
Other cash flow hedges	$ (5)	$ (5)		Interest expense
Total before tax	(5)	(5)		
Tax expense	2	2		
Net of tax	$ (3)	$ (3)	$	Comprehensive income
Amortization of pension and other postretirement benefit plan items				
Prior service costs[b]	$ 20	$	$	
Actuarial losses[b]	(76)		(1)	

Total before tax		(56)				(1)	
Tax benefit		22					
Net of tax	$	(34)	$		$	(1)	
Total Reclassifications	$	(37)	$	(3)	$	(1)	Comprehensive income

(a) Amounts in parenthesis represent a decrease in net income.
(b) This AOCI component is included in the computation of net periodic pension and OPEB cost (see Note 13 Retirement Benefits for additional details).

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following table presents income tax expense (benefit) allocated to each component of other comprehensive income (loss) during the three months ended March 31, 2017 and 2016:

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Exelon		
Pension and non-pension postretirement benefit plans:		
Prior service benefit reclassified to periodic benefit cost	$ 10	$ 7
Actuarial loss reclassified to periodic benefit cost	(32)	(30)
Pension and non-pension postretirement benefit plans valuation adjustment		
Change in unrealized (loss)/gain on cash flow hedges	(1)	3
Change in unrealized (loss)/gain on equity investments	(4)	2
Change in unrealized (loss)/gain on marketable securities	(1)	1
Total	$ (28)	$ (17)
Generation		
Change in unrealized (loss)/gain on cash flow hedges	$ (1)	$ 2
Change in unrealized (loss)/gain on equity investments	(3)	2
Total	$ (4)	$ 4

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

16. Earnings Per Share and Equity (Exelon)

Earnings per Share

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

	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016

Exelon		
Net income attributable to common shareholders	$ 995	$ 173
Weighted average common shares outstanding basic	928	923
Assumed exercise and/or distributions of stock-based awards	2	2
Weighted average common shares outstanding diluted	930	925

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 9 million and 13 million for the three months ended March 31, 2017 and 2016, respectively. There were no equity units related to the PHI Merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect for the three months ended March 31, 2017. The number of equity units related to the PHI Merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect was 4 million for the three months ended March 31, 2016. Refer to Note 20 Shareholders Equity of the Exelon 2016 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 March 31, 2017. In 2008, Exelon management decided to defer indefinitely any share repurchases.

17. Commitments and Contingencies (*All Registrants*)

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

Commitments

Constellation Merger Commitments (Exelon and Generation)

In February 2012, the MDPSC issued an Order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion. The direct investment 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 $450 million to $550 million relating to Exelon and Generation s development or assistance in the development of 285 300 MWs of new generation in Maryland, which is expected to be completed within a period of 10 years. The MDPSC order contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed or certain specified provisions are elected, making liquidated damages payments. Exelon and Generation have incurred $456 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. During the fourth quarter of 2016, given continued declines in projected energy and capacity prices, Generation terminated rights to certain development projects originally intended to meet its remaining 55 MW commitment amount. The commitment will now most likely be satisfied via payment of liquidated damages or execution of a third party PPA, rather than by Generation constructing renewable generating assets. As a result, Exelon and Generation recorded a pre-tax $50 million loss contingency in Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2016.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Equity Investment Commitments (Exelon and Generation)

As part of Generation s recent investments in technology development, Generation enters into equity purchase agreements that include commitments to invest additional equity through incremental payments to fund the anticipated needs of the planned operations of the associated companies. As of March 31, 2017, Generation s estimated commitments relating to its equity purchase agreements, including the in-kind services contributions, is anticipated to be as follows:

	Total
2017	$ 9
2018	7
2019	3
Total	$ 19

Commercial Commitments (All Registrants)

The Registrants commercial commitments as of March 31, 2017 , representing commitments potentially triggered by future events were as follows:

	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Letters of credit (non-debt)[(a)]	$ 1,527	$ 1,440	$ 14	$ 23	$ 5	$ 1	$ 1	$	$
Surety bonds[(b)]	1,038	964	5	7	11	16	9	4	3
Financing trust guarantees	628		200	178	250				
Guaranteed lease residual values[(c)]	19					19	5	7	5
Total commercial commitments	$ 3,212	$ 2,404	$ 219	$ 208	$ 266	$ 36	$ 15	$ 11	$ 8

(a) Letters of credit (non-debt) Exelon and certain subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $48 million, $14 million of which is a guarantee by Pepco, $17 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 March 31, 2017 , the current liability limit per incident is

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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