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

FORM 10-Q

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

For the Quarterly Period Ended September 30, 2014

or

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

Commission File Number	Name of Registrant; State 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 (312) 394-7398	23-2990190
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210

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

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

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

	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company
Exelon Corporation	☒			
Exelon Generation Company, LLC			☒	
Commonwealth Edison Company			☒	
PECO Energy Company			☒	
Baltimore Gas and Electric Company			☒	

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

The number of shares outstanding of each registrant's common stock as of September 30, 2014 was:

Exelon Corporation Common Stock, without par value	859,464,772
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,934
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities	
Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon in its corporate capacity as a holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
Antelope Valley	Antelope Valley Solar Ranch One
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
BondCo	RSB BondCo LLC
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
Registrants	Exelon, Generation, ComEd, PECO and BGE, collectively

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
Note "—" of the Exelon 2013 Form 10-K	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2013 Annual Report on Form 10-K
1998 restructuring settlement	PECO's 1998 settlement of its restructuring case mandated by the Competition Act
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
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
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
AMP	Advanced Metering Program
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Title IV Acid Rain Program
ARRA of 2009	American Recovery and Reinvestment Act of 2009
Block contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAMR	Federal Clean Air Mercury Rule

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
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
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTC	Competitive Transition Charge
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDF	Electricite de France SA
EE&C	Energy Efficiency and Conservation/Demand Response
EGS	Electric Generation Supplier
EGTP	ExGen Texas Power, LLC
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas
GRT	Gross Receipts Tax
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
HAP	Hazardous air pollutants
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
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
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
ISO-NE	ISO New England Inc.
ISO-NY	ISO New York
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LILO	Lease-In, Lease-Out
LLRW	Low-Level Radioactive Waste
LTIP	Long-Term Incentive Plan
MATS	U.S. EPA Mercury and Air Toxics Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
Moody's	Moody's Investor Service
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
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
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
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PHI	Pepco Holdings, Inc.
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
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 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
RMC	Risk Management Committee
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
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)
SERP	Supplemental Employee Retirement Plan
SGIG	Smart Grid Investment Grant
SGIP	Smart Grid Initiative Program
SILO	Sale-In, Lease-Out
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
Upstream	Natural gas exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

FILING FORMAT

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

FORWARD-LOOKING STATEMENTS

This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, as well as the items discussed in (1) Exelon's 2013 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 22; (2) this Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors, (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

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

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

(In millions, except per share data)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Operating revenues	$ 6,912	$ 6,502	$20,173	$18,725
Operating expenses				
Purchased power and fuel	2,591	2,404	8,943	7,199
Purchased power and fuel from affiliates	57	339	456	944
Operating and maintenance	1,982	1,735	6,005	5,391
Depreciation and amortization	577	530	1,732	1,606
Taxes other than income	306	277	887	825
Total operating expenses	5,513	5,285	18,023	15,965
Equity in earnings (loss) of unconsolidated affiliates	1	37	(20)	7
Gain on consolidation of CENG	—	—	261	—
Operating income	1,400	1,254	2,391	2,767
Other income and (deductions)				
Interest expense, net	(247)	(228)	(691)	(1,091)
Interest expense to affiliates, net	(11)	(6)	(31)	(19)
Other, net	354	155	702	311
Total other income and (deductions)	96	(79)	(20)	(799)
Income before income taxes	1,496	1,175	2,371	1,968
Income taxes	422	439	646	733
Net income	1,074	736	1,725	1,235
Net income (loss) attributable to noncontrolling interest, preferred security dividends and redemption and preference stock dividends	81	(2)	121	11
Net income attributable to common shareholders	993	738	1,604	1,224
Comprehensive income, net of income taxes				
Net income	1,074	736	1,725	1,235
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service (benefit) cost reclassified to periodic benefit cost	(11)	1	(18)	—
Actuarial loss reclassified to periodic cost	38	49	109	151
Pension and non-pension postretirement benefit plans valuation adjustment	(8)	(8)	240	69
Deferred compensation unit valuation adjustment	—	—	—	10
Unrealized (loss) on cash flow hedges	(19)	(46)	(92)	(169)
Unrealized gain (loss) on equity investments	(3)	16	8	51
Unrealized (loss) on foreign currency translation	(5)	—	(6)	(5)
Unrealized (loss) on marketable securities	(3)	—	(2)	(1)
Reversal of CENG equity method AOCI	—	—	(116)	—
Other comprehensive income (loss)	(11)	12	123	106
Comprehensive income	$ 1,063	$ 748	$ 1,848	$ 1,341
Average shares of common stock outstanding:				
Basic	861	857	860	856
Diluted	863	860	863	860
Earnings per average common share:				
Basic	$ 1.15	$ 0.86	$ 1.87	$ 1.43
Diluted	$ 1.15	$ 0.86	$ 1.86	$ 1.42
Dividends per common share	$ 0.31	$ 0.31	$ 0.93	$ 1.15

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2014	2013
Cash flows from operating activities		
Net income	$ 1,725	$ 1,235
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	2,856	2,844
Impairment of long-lived assets	162	171
Gain on consolidation of CENG	(268)	—
Gain on sale of assets	(356)	(17)
Deferred income taxes and amortization of investment tax credits	459	(164)
Net fair value changes related to derivatives	522	(229)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(141)	(95)
Other non-cash operating activities	698	584
Changes in assets and liabilities:		
Accounts receivable	198	54
Inventories	(316)	(103)
Accounts payable, accrued expenses and other current liabilities	(322)	(243)
Option premiums received (paid), net	21	(38)
Counterparty collateral posted, net	(615)	(73)
Income taxes	72	863
Pension and non-pension postretirement benefit contributions	(516)	(360)
Other assets and liabilities	(536)	(35)
Net cash flows provided by operating activities	3,643	4,394
Cash flows from investing activities		
Capital expenditures	(4,114)	(3,887)
Proceeds from nuclear decommissioning trust fund sales	5,464	3,344
Investment in nuclear decommissioning trust funds	(5,550)	(3,518)
Acquisition of businesses	(67)	—
Proceeds from sale of long-lived assets	660	32
Proceeds from termination of direct financing lease investment	335	—
Proceeds from sale of investments	7	20
Purchases of investments	(3)	(3)
Cash consolidated from CENG	129	—
Change in restricted cash	(151)	(23)
Other investing activities	(86)	65
Net cash flows used in investing activities	(3,376)	(3,970)
Cash flows from financing activities		
Payment of accounts receivable agreement	—	(210)
Changes in short-term borrowings	236	205
Issuance of long-term debt	3,212	2,031
Retirement of long-term debt	(1,214)	(1,156)
Redemption of preferred securities	—	(93)
Distributions to noncontrolling interest of consolidated VIE	(415)	—
Dividends paid on common stock	(799)	(981)
Proceeds from employee stock plans	25	40
Other financing activities	(158)	(102)
Net cash flows provided by (used in) financing activities	887	(266)
Increase in cash and cash equivalents	1,154	158
Cash and cash equivalents at beginning of period	1,609	1,486
Cash and cash equivalents at end of period	$ 2,763	$ 1,644

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 2,763	$ 1,609
Restricted cash and cash equivalents	318	167
Accounts receivable, net		
Customer	2,815	2,981
Other	898	1,175
Mark-to-market derivative assets	744	727
Unamortized energy contract assets	225	374
Inventories, net		
Fossil fuel	546	276
Materials and supplies	1,045	829
Deferred income taxes	38	573
Regulatory assets	774	760
Assets held for sale	649	14
Other	1,022	652
Total current assets	11,837	10,137
Property, plant and equipment, net	51,630	47,330
Deferred debits and other assets		
Regulatory assets	5,589	5,910
Nuclear decommissioning trust funds	10,349	8,071
Investments	562	1,165
Investments in affiliates	26	22
Investment in CENG	—	1,925
Goodwill	2,672	2,625
Mark-to-market derivative assets	524	607
Unamortized energy contracts assets	571	710
Pledged assets for Zion Station decommissioning	365	458
Other	1,139	964
Total deferred debits and other assets	21,797	22,457
Total assets[(a)]	$ 85,264	$ 79,924

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2014 (Unaudited)	December 31, 2013
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 562	$ 341
Long-term debt due within one year	2,064	1,509
Accounts payable	2,502	2,484
Accrued expenses	1,462	1,633
Payables to affiliates	22	116
Deferred income taxes	26	40
Regulatory liabilities	364	327
Mark-to-market derivative liabilities	249	159
Unamortized energy contract liabilities	195	261
Other	985	858
Total current liabilities	8,431	7,728
Long-term debt	19,200	17,623
Long-term debt to financing trusts	648	648
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	13,181	12,905
Asset retirement obligations	7,003	5,194
Pension obligations	1,809	1,876
Non-pension postretirement benefit obligations	1,459	2,190
Spent nuclear fuel obligation	1,021	1,021
Regulatory liabilities	4,593	4,388
Mark-to-market derivative liabilities	291	300
Unamortized energy contract liabilities	214	266
Payable for Zion Station decommissioning	260	305
Other	2,104	2,540
Total deferred credits and other liabilities	31,935	30,985
Total liabilities[(a)]	60,214	56,984
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 859 shares and 857 shares outstanding at September 30, 2014 and December 31, 2013, respectively)	16,679	16,741
Treasury stock, at cost (35 shares at both September 30, 2014 and December 31, 2013)	(2,327)	(2,327)
Retained earnings	11,160	10,358
Accumulated other comprehensive loss, net	(1,917)	(2,040)
Total shareholders' equity	23,595	22,732
BGE preference stock not subject to mandatory redemption	193	193
Noncontrolling interest	1,262	15
Total equity	25,050	22,940
Total liabilities and shareholders' equity	$ 85,264	$ 79,924

(a) Exelon's consolidated assets include $7,773 million and $1,755 million at September 30, 2014 and December 31, 2013, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $2,594 million and $658 million at September 30, 2014 and December 31, 2013, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 3 — Variable Interest Entities.

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

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interest	Preferred and Preference Stock	Total Equity
Balance, December 31, 2013	892,034	$16,741	$(2,327)	$10,358	$ (2,040)	$ 15	$ 193	$22,940
Net income	—	—	—	1,604	—	111	10	1,725
Long-term incentive plan activity	1,439	49	—	—	—	—	—	49
Employee stock purchase plan issuances	735	25	—	—	—	—	—	25
Tax benefit on stock compensation	—	(7)	—	—	—	—	—	(7)
Acquisition of noncontrolling interest	—	—	—	—	—	3	—	3
Common stock dividends	—	—	—	(802)	—	—	—	(802)
Preferred and preference stock dividends	—	—	—	—	—	—	(10)	(10)
Fair value of financing contract payments	—	(131)	—	—	—	—	—	(131)
Noncontrolling interest established upon consolidation of CENG	—	—	—	—	—	1,548	—	1,548
Transfer of CENG pension and non-pension post retirement benefit obligations	—	2	—	—	—	—	—	2
Consolidated VIE dividend to noncontrolling interest	—	—	—	—	—	(415)	—	(415)
Reversal of CENG equity method AOCI, net of income taxes of $77	—	—	—	—	(116)	—	—	(116)
Other comprehensive income net of income taxes of $(154)	—	—	—	—	239	—	—	239
Balance, September 30, 2014	894,208	$16,679	$(2,327)	$11,160	$ (1,917)	$ 1,262	$ 193	$25,050

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Operating revenues				
Operating revenues	$ 4,300	$ 3,871	$11,944	$10,729
Operating revenues from affiliates	112	384	647	1,129
Total operating revenues	4,412	4,255	12,591	11,858
Operating expenses				
Purchased power and fuel	1,821	1,837	6,595	5,341
Purchased power and fuel from affiliates	59	342	476	953
Operating and maintenance	1,114	936	3,308	2,943
Operating and maintenance from affiliates	152	140	457	434
Depreciation and amortization	253	218	719	643
Taxes other than income	127	98	350	292
Total operating expenses	3,526	3,571	11,905	10,606
Equity in earnings (losses) of unconsolidated affiliates	1	37	(20)	7
Gain on consolidation of CENG	—	—	261	—
Operating income	887	721	927	1,259
Other income and (deductions)				
Interest expense	(77)	(69)	(224)	(210)
Interest expense to affiliates, net	(12)	(13)	(37)	(47)
Other, net	342	134	661	229
Total other income and (deductions)	253	52	400	(28)
Income before income taxes	1,140	773	1,327	1,231
Income taxes	291	288	290	436
Net income	849	485	1,037	795
Net income (loss) attributable to noncontrolling interests	78	(5)	111	(6)
Net income attributable to membership interest	771	490	926	801
Comprehensive income, net of income taxes				
Net income	849	485	1,037	795
Other comprehensive income (loss), net of income taxes				
Unrealized loss on cash flow hedges	(16)	(49)	(86)	(316)
Unrealized gain (loss) on equity investments	(3)	16	8	52
Unrealized gain (loss) on foreign currency translation	(5)	1	(6)	(5)
Unrealized loss on marketable securities	(2)	—	(3)	(1)
Reversal of CENG equity method AOCI	—	—	(116)	—
Other comprehensive loss	(26)	(32)	(203)	(270)
Comprehensive income	$ 823	$ 453	$ 834	$ 525

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2014	2013
Cash flows from operating activities		
Net income	$ 1,037	$ 795
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	1,853	1,937
Impairment of long-lived assets	138	157
Gain on consolidation of CENG	(268)	—
Gain on sale of assets	(355)	(13)
Deferred income taxes and amortization of investment tax credits	154	183
Net fair value changes related to derivatives	509	(222)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(141)	(95)
Other non-cash operating activities	251	231
Changes in assets and liabilities:		
Accounts receivable	153	57
Receivables from and payables to affiliates, net	72	2
Inventories	(286)	(81)
Accounts payable, accrued expenses and other current liabilities	(311)	(162)
Option premiums received (paid), net	21	(38)
Counterparty collateral paid, net	(634)	(123)
Income taxes	172	315
Pension and non-pension postretirement benefit contributions	(214)	(123)
Other assets and liabilities	(367)	(163)
Net cash flows provided by operating activities	1,784	2,657
Cash flows from investing activities		
Capital expenditures	(1,961)	(1,995)
Proceeds from nuclear decommissioning trust fund sales	5,464	3,344
Investment in nuclear decommissioning trust funds	(5,550)	(3,518)
Acquisition of businesses	(67)	—
Proceeds from sale of long-lived assets	660	32
Change in restricted cash	(116)	(30)
Changes in Exelon intercompany money pool	44	—
Cash consolidated from CENG	129	—
Other investing activities	(34)	18
Net cash flows used in investing activities	(1,431)	(2,149)
Cash flows from financing activities		
Change in short-term borrowings	7	12
Issuance of long-term debt	1,112	831
Retirement of long-term debt	(552)	(471)
Distribution to member	(440)	(550)
Distributions to noncontrolling interest of consolidated VIE	(415)	—
Contribution from member	55	—
Other financing activities	(67)	(73)
Net cash flows used in financing activities	(300)	(251)
Increase in cash and cash equivalents	53	257
Cash and cash equivalents at beginning of period	1,258	671
Cash and cash equivalents at end of period	$ 1,311	$ 928

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,311	$ 1,258
Restricted cash and cash equivalents	187	71
Accounts receivable, net		
Customer	1,705	1,689
Other	325	353
Mark-to-market derivative assets	744	727
Receivables from affiliates	56	108
Receivable from Exelon intercompany money pool	—	44
Unamortized energy contract assets	225	374
Inventories, net		
Fossil fuel	426	164
Materials and supplies	865	671
Deferred income taxes	144	475
Assets held for sale	649	14
Other	821	491
Total current assets	7,458	6,439
Property, plant and equipment, net	23,143	20,111
Deferred debits and other assets		
Nuclear decommissioning trust funds	10,349	8,071
Investments	154	400
Investment in CENG	—	1,925
Goodwill	47	—
Mark-to-market derivative assets	507	600
Prepaid pension asset	1,711	1,873
Pledged assets for Zion Station decommissioning	365	458
Unamortized energy contract assets	571	710
Other	714	645
Total deferred debits and other assets	14,418	14,682
Total assets[a]	$ 45,019	$ 41,232

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2014 (Unaudited)	December 31, 2013
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 14	$ 22
Long-term debt due within one year	73	561
Long-term debt to affiliates due within one year	560	—
Accounts payable	1,318	1,322
Accrued expenses	840	976
Payables to affiliates	124	181
Deferred income taxes	1	25
Mark-to-market derivative liabilities	235	142
Unamortized energy contract liabilities	192	249
Other	478	389
Total current liabilities	3,835	3,867
Long-term debt	6,741	5,645
Long-term debt to affiliate	946	1,523
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	6,202	6,295
Asset retirement obligations	6,853	5,047
Non-pension postretirement benefit obligations	949	850
Spent nuclear fuel obligation	1,021	1,021
Payables to affiliates	2,850	2,740
Mark-to-market derivative liabilities	104	120
Unamortized energy contract liabilities	214	266
Payable for Zion Station decommissioning	260	305
Other	718	811
Total deferred credits and other liabilities	19,171	17,455
Total liabilities[(a)]	30,693	28,490
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	8,953	8,898
Undistributed earnings	4,099	3,613
Accumulated other comprehensive income, net	11	214
Total member's equity	13,063	12,725
Noncontrolling interest	1,263	17
Total equity	14,326	12,742
Total liabilities and equity	$ 45,019	$ 41,232

(a) Generation's consolidated assets include $7,703 million and $1,695 million at September 30, 2014 and December 31, 2013, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include $2,338 million and $362 million at September 30, 2014 and December 31, 2013, 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

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 Income, net	Noncontrolling Interest	Total Equity
Balance, December 31, 2013	$ 8,898	$ 3,613	$ 214	$ 17	$12,742
Net income	—	926	—	111	1,037
Acquisition of noncontrolling interest	—	—	—	2	2
Allocation of tax benefit from member	55	—	—	—	55
Distribution to member	—	(440)	—	—	(440)
Noncontrolling interest established upon consolidation of CENG	—	—	—	1,548	1,548
Consolidated VIE dividend to noncontrolling interest	—	—	—	(415)	(415)
Reversal of CENG equity method AOCI, net of income taxes of $77	—	—	(116)	—	(116)
Other comprehensive loss, net of income taxes of $53	—	—	(87)	—	(87)
Balance, September 30, 2014	$ 8,953	$ 4,099	$ 11	$ 1,263	$14,326

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Operating revenues				
Operating revenues	$ 1,221	$ 1,155	$ 3,482	$ 3,393
Operating revenues from affiliates	1	1	2	2
Total operating revenues	1,222	1,156	3,484	3,395
Operating expenses				
Purchased power	325	158	741	522
Purchased power from affiliate	1	143	174	409
Operating and maintenance	320	296	923	907
Operating and maintenance from affiliate	39	37	117	113
Depreciation and amortization	174	164	521	501
Taxes other than income	76	80	225	225
Total operating expenses	935	878	2,701	2,677
Operating income	287	278	783	718
Other income and (deductions)				
Interest expense	(78)	(71)	(231)	(493)
Interest expense to affiliates, net	(3)	(3)	(10)	(10)
Other, net	4	7	14	18
Total other income and (deductions)	(77)	(67)	(227)	(485)
Income before income taxes	210	211	556	233
Income taxes	84	85	221	93
Net income	$ 126	$ 126	$ 335	$ 140
Comprehensive income	$ 126	$ 126	$ 335	$ 140

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Cash flows from operating activities		
Net income	$ 335	$ 140
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	521	501
Deferred income taxes and amortization of investment tax credits	154	(152)
Other non-cash operating activities	116	26
Changes in assets and liabilities:		
Accounts receivable	(109)	(21)
Receivables from and payables to affiliates, net	(55)	(32)
Inventories	(12)	(12)
Accounts payable, accrued expenses and other current liabilities	59	48
Income taxes	15	262
Pension and non-pension postretirement benefit contributions	(237)	(120)
Other assets and liabilities	62	210
Net cash flows provided by operating activities	849	850
Cash flows from investing activities		
Capital expenditures	(1,173)	(1,074)
Proceeds from sales of investments	7	5
Purchases of investments	(3)	(3)
Change in restricted cash	(2)	(3)
Other investing activities	23	33
Net cash flows used in investing activities	(1,148)	(1,042)
Cash flows from financing activities		
Changes in short-term borrowings	344	153
Issuance of long-term debt	650	350
Retirement of long-term debt	(617)	(252)
Contributions from parent	168	—
Dividends paid on common stock	(230)	(165)
Other financing activities	(8)	(4)
Net cash flows provided by financing activities	307	82
Increase (Decrease) in cash and cash equivalents	8	(110)
Cash and cash equivalents at beginning of period	36	144
Cash and cash equivalents at end of period	$ 44	$ 34

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 44	$ 36
Restricted cash	4	2
Accounts receivable, net		
Customer	486	451
Other	455	581
Receivables from affiliates	3	3
Inventories, net	121	109
Regulatory assets	330	329
Other	37	29
Total current assets	1,480	1,540
Property, plant and equipment, net	15,389	14,666
Deferred debits and other assets		
Regulatory assets	928	933
Investments	—	5
Investments in affiliates	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,551	2,469
Prepaid pension asset	1,588	1,583
Other	278	291
Total deferred debits and other assets	7,976	7,912
Total assets	$ 24,845	$ 24,118

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2014 (Unaudited)	December 31, 2013
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 528	$ 184
Long-term debt due within one year	260	617
Accounts payable	571	449
Accrued expenses	254	307
Payables to affiliates	28	83
Customer deposits	128	133
Regulatory liabilities	187	170
Deferred income taxes	117	16
Mark-to-market derivative liability	14	17
Other	73	72
Total current liabilities	2,160	2,048
Long-term debt	5,448	5,058
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,170	4,116
Asset retirement obligations	103	99
Non-pension postretirement benefits obligations	278	381
Regulatory liabilities	3,643	3,512
Mark-to-market derivative liability	164	176
Other	868	994
Total deferred credits and other liabilities	9,226	9,278
Total liabilities	17,040	16,590
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	5,362	5,190
Retained earnings	855	750
Total shareholders' equity	7,805	7,528
Total liabilities and shareholders' equity	$ 24,845	$ 24,118

See the Combined Notes to Consolidated Financial Statements

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, 2013	$ 1,588	$ 5,190	$ (1,639)	$ 2,389	$ 7,528
Net income	—	—	335	—	335
Appropriation of retained earnings for future dividends	—	—	(335)	335	—
Common stock dividends	—	—	—	(230)	(230)
Contribution from parent	—	168	—	—	168
Parent tax matter indemnification	—	4	—	—	4
Balance, September 30, 2014	$ 1,588	$ 5,362	$ (1,639)	$ 2,494	$ 7,805

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Operating revenues				
Operating revenues	$ 693	$ 727	$ 2,342	$ 2,294
Operating revenues from affiliates	—	1	1	1
Total operating revenues	693	728	2,343	2,295
Operating expenses				
Purchased power and fuel	228	207	798	632
Purchased power from affiliate	27	82	162	321
Operating and maintenance	181	162	597	480
Operating and maintenance from affiliates	23	24	71	74
Depreciation and amortization	59	57	176	171
Taxes other than income	42	41	122	121
Total operating expenses	560	573	1,926	1,799
Operating income	133	155	417	496
Other income and (deductions)				
Interest expense	(26)	(26)	(76)	(77)
Interest expense to affiliates, net	(3)	(3)	(9)	(9)
Other, net	2	1	5	4
Total other income and (deductions)	(27)	(28)	(80)	(82)
Income before income taxes	106	127	337	414
Income taxes	25	35	82	122
Net income	81	92	255	292
Preferred security dividends and redemption	—	—	—	7
Net income attributable to common shareholder	$ 81	$ 92	$ 255	$ 285
Comprehensive income	$ 81	$ 92	$ 255	$ 292

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2014	2013
Cash flows from operating activities		
Net income	$ 255	$ 292
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	176	171
Deferred income taxes and amortization of investment tax credits	7	35
Other non-cash operating activities	70	84
Changes in assets and liabilities:		
Accounts receivable	63	41
Receivables from and payables to affiliates, net	(20)	(25)
Inventories	5	4
Accounts payable, accrued expenses and other current liabilities	19	9
Income taxes	16	66
Pension and non-pension postretirement benefit contributions	(12)	(10)
Other assets and liabilities	(75)	(47)
Net cash flows provided by operating activities	504	620
Cash flows from investing activities		
Capital expenditures	(461)	(374)
Changes in intercompany money pool	—	(1)
Change in restricted cash	—	(1)
Other investing activities	9	8
Net cash flows used in investing activities	(452)	(368)
Cash flows from financing activities		
Payment of accounts receivable agreement	—	(210)
Issuance of long-term debt	300	550
Contributions from parent	24	—
Dividends paid on common stock	(240)	(248)
Dividends paid on preferred securities	—	(1)
Redemption of preferred securities	—	(93)
Other financing activities	(7)	(3)
Net cash flows provided by (used in) financing activities	77	(5)
Increase in cash and cash equivalents	129	247
Cash and cash equivalents at beginning of period	217	362
Cash and cash equivalents at end of period	$ 346	$ 609

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 346	$ 217
Restricted cash and cash equivalents	2	2
Accounts receivable, net		
Customer	258	360
Other	105	103
Receivables from affiliates	3	4
Inventories, net		
Fossil fuel	52	60
Materials and supplies	24	21
Deferred income taxes	83	83
Prepaid utility taxes	44	3
Regulatory assets	21	17
Other	44	36
Total current assets	982	906
Property, plant and equipment, net	6,648	6,384
Deferred debits and other assets		
Regulatory assets	1,520	1,448
Investments	23	23
Investments in affiliates	8	8
Receivable from affiliates	479	447
Prepaid pension asset	352	363
Other	39	38
Total deferred debits and other assets	2,421	2,327
Total assets	$ 10,051	$ 9,617

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2014 (Unaudited)	December 31, 2013
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long-term debt due within one year	$ 250	$ 250
Accounts payable	303	285
Accrued expenses	121	106
Payables to affiliates	38	58
Customer deposits	53	49
Regulatory liabilities	79	106
Other	26	37
Total current liabilities	870	891
Long-term debt	2,246	1,947
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,574	2,487
Asset retirement obligations	30	29
Non-pension postretirement benefits obligations	291	286
Regulatory liabilities	655	629
Other	97	99
Total deferred credits and other liabilities	3,647	3,530
Total liabilities	6,947	6,552
Commitments and contingencies		
Shareholder's equity		
Common stock	2,439	2,415
Retained earnings	664	649
Accumulated other comprehensive income, net	1	1
Total shareholder's equity	3,104	3,065
Total liabilities and shareholder's equity	$ 10,051	$ 9,617

See the Combined Notes to Consolidated Financial Statements

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, 2013	$ 2,415	$ 649	$ 1	$ 3,065
Net income	—	255	—	255
Common stock dividends	—	(240)	—	(240)
Allocation of tax benefit from parent	$ 24	$ —	$ —	$ 24
Balance, September 30, 2014	$ 2,439	$ 664	$ 1	$ 3,104

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Operating revenues				
Operating revenues	$ 694	$ 735	$ 2,383	$ 2,261
Operating revenues from affiliates	3	2	21	10
Total operating revenues	697	737	2,404	2,271
Operating expenses				
Purchased power and fuel	216	202	808	703
Purchased power from affiliate	81	144	286	356
Operating and maintenance	142	125	468	391
Operating and maintenance from affiliates	23	21	73	59
Depreciation and amortization	78	78	275	252
Taxes other than income	55	53	168	162
Total operating expenses	595	623	2,078	1,923
Operating income	102	114	326	348
Other income and (deductions)				
Interest expense	(22)	(25)	(69)	(82)
Interest expense to affiliates, net	(4)	(4)	(12)	(12)
Other, net	4	4	14	13
Total other income and (deductions)	(22)	(25)	(67)	(81)
Income before income taxes	80	89	259	267
Income taxes	31	36	103	107
Net income	49	53	156	160
Preference stock dividends	3	3	10	10
Net income attributable to common shareholder	$ 46	$ 50	$ 146	$ 150
Comprehensive income	$ 49	$ 53	$ 156	$ 160

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Cash flows from operating activities		
Net income	$ 156	$ 160
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	275	252
Deferred income taxes and amortization of investment tax credits	57	105
Other non-cash operating activities	129	105
Changes in assets and liabilities:		
Accounts receivable	101	(28)
Receivables from and payables to affiliates, net	(11)	(12)
Inventories	(21)	(15)
Accounts payable, accrued expenses and other current liabilities	(50)	(5)
Counterparty collateral received, net	16	—
Income taxes	53	6
Pension and non-pension postretirement benefit contributions	(13)	(16)
Other assets and liabilities	(67)	(119)
Net cash flows provided by operating activities	625	433
Cash flows from investing activities		
Capital expenditures	(458)	(391)
Change in restricted cash	(37)	(20)
Other investing activities	15	2
Net cash flows used in investing activities	(480)	(409)
Cash flows from financing activities		
Changes in short-term borrowings	(115)	40
Issuance of long-term debt	—	300
Retirement of long-term debt	(35)	(433)
Dividends paid on preference stock	(10)	(10)
Other financing activities	11	(3)
Net cash flows used in financing activities	(149)	(106)
Decrease in cash and cash equivalents	(4)	(82)
Cash and cash equivalents at beginning of period	31	89
Cash and cash equivalents at end of period	$ 27	$ 7

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 27	$ 31
Restricted cash and cash equivalents	65	28
Accounts receivable, net		
Customer	366	480
Other	90	114
Income taxes receivable	—	30
Inventories, net		
Gas held in storage	68	53
Materials and supplies	34	28
Deferred income taxes	5	2
Prepaid utility taxes	2	57
Regulatory assets	206	181
Other	6	7
Total current assets	869	1,011
Property, plant and equipment, net	6,126	5,864
Deferred debits and other assets		
Regulatory assets	500	524
Investments	4	5
Investments in affiliates	8	8
Prepaid pension asset	382	423
Other	26	26
Total deferred debits and other assets	920	986
Total assets[(a)]	$ 7,915	$ 7,861

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2014 (Unaudited)	December 31, 2013
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 20	$ 135
Long-term debt due within one year	72	70
Accounts payable	207	270
Accrued expenses	167	111
Deferred income taxes	52	27
Payables to affiliates	56	55
Customer deposits	93	76
Regulatory liabilities	45	48
Other	45	35
Total current liabilities	757	827
Long-term debt	1,904	1,941
Long-term debt to financing trust	258	258
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,805	1,773
Asset retirement obligations	18	19
Non-pension postretirement benefits obligations	213	217
Regulatory liabilities	199	204
Other	60	67
Total deferred credits and other liabilities	2,295	2,280
Total liabilities[a]	5,214	5,306
Commitments and contingencies		
Shareholders' equity		
Common stock	1,360	1,360
Retained earnings	1,151	1,005
Total shareholder's equity	2,511	2,365
Preference stock not subject to mandatory redemption	190	190
Total equity	2,701	2,555
Total liabilities and shareholders' equity	$ 7,915	$ 7,861

(a) BGE's consolidated assets include $50 million and $31 million at September 30, 2014 and December 31, 2013, respectively, of BGE's consolidated VIE that can only be used to settle the liabilities of the VIE. BGE's consolidated liabilities include $237 million and $269 million at September 30, 2014 and December 31, 2013, 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

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

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2013	$ 1,360	$ 1,005	$ 2,365	$ 190	$ 2,555
Net income	—	156	156	—	156
Preference stock dividends	—	(10)	(10)	—	(10)
Balance, September 30, 2014	$ 1,360	$ 1,151	$ 2,511	$ 190	$ 2,701

See the Combined Notes to Consolidated Financial Statements

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

1. Basis of Presentation (Exelon, Generation, ComEd, PECO and BGE)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution businesses. On April 1, 2014, Generation assumed the operating licenses and corresponding operational control of CENG's nuclear fleet. As a result, Exelon and Generation consolidated CENG's financial position and results of operations into their businesses. Prior to April 1, 2014, Exelon and Generation accounted for CENG as an equity method investment. Refer to Note 6 — Investment in Constellation Energy Nuclear Group, LLC for further information regarding the integration transaction.

The energy generation business includes:

- *Generation*: Physical delivery and marketing of owned and contracted electric generation capacity and provision of renewable and other energy-related products and services, and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other regions.

The energy delivery businesses include:

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

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

Certain prior year amounts in ComEd's and PECO's Consolidated Balance Sheets have been reclassified between line items for comparative purposes. The reclassifications did not affect any of the Registrants' net income or cash flows from operating activities.

Certain prior year amounts in the Exelon, Generation and BGE Consolidated Statement of Operations have been reclassified between line items for correction of prior period classification errors. Exelon corrected the presentation of Purchased power and fuel from affiliates of $339 million and $944 million on its Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2013, respectively. Generation corrected the presentation of Purchased power and fuel from affiliates of $342 million and $953 million on its Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2013, respectively. Generation also corrected the presentation of Interest expense to affiliates, net of $13 million and $47 million on its Statement of Operations and Comprehensive Income for the three and nine months ended September 30, 2013, respectively. BGE corrected its presentation of Interest expense to affiliates, net of $4 million and $12 million on the Statement of Operations and Comprehensive Income for the three and nine months ended September 30, 2013, respectively.

The accompanying consolidated financial statements as of September 30, 2014 and 2013 and for the nine 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, 2013 Consolidated Balance Sheets were obtained from audited financial statements. Financial results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for the fiscal year ending December 31, 2014. 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. These notes should be read in conjunction with the Notes to Combined Consolidated Financial Statements of all Registrants included in ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA of their respective 2013 Form 10-K Reports.

2. New Accounting Pronouncements (Exelon, Generation, ComEd, PECO and BGE)

The following recently issued accounting standards were adopted by or are effective for the Registrants during 2014.

Presentation of Unrecognized Tax Benefits When Net Operating Loss Carryforwards, Similar Tax Losses or Tax Credit Carryforwards Exist

In July 2013, the FASB issued authoritative guidance requiring entities to present unrecognized tax benefits as a reduction to deferred tax assets for losses or other tax carryforwards that would be available to offset the uncertain tax positions at the reporting date. This guidance was effective for the Registrants for periods beginning after December 15, 2013 and was required to be applied prospectively. The adoption of this standard had an immaterial effect on the presentation of deferred tax assets at Exelon and Generation and no effect on ComEd, PECO and BGE. There was no effect on the Registrants' results of operations or cash flows.

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

Revenue from Contracts with Customers

In May 2014, the FASB issued authoritative guidance that changes the criteria for recognizing revenue from a contract with a customer. The new guidance replaces existing guidance on revenue recognition, including most industry specific guidance, with a five step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing and uncertainty of revenue and the related cash flows. The guidance is effective for the Registrants for the first interim period within annual reporting periods beginning on or after December 15, 2016. Early adoption is not permitted. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Registrants are currently assessing the impacts this guidance may have on their financial positions, results of operations, cash flows and disclosures as well as the transition method that they will use to adopt the guidance.

3. Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

Under the applicable authoritative guidance, 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 September 30, 2014 and December 31, 2013, Exelon, Generation, and BGE collectively consolidated six and four VIEs or VIE groups, respectively, for which the applicable Registrant was the primary beneficiary *(see Consolidated Variable Interest Entities below)*. As of September 30, 2014 and December 31, 2013, the Registrants had significant interests in eight other VIEs for which the Registrants do not have the power to direct the entities' activities and, accordingly, were not the primary beneficiary.

Through March 31, 2014, CENG was operated as a joint venture with EDF Inc. (EDFI) (a subsidiary of EDF) and was governed by a board of ten directors, five of which were appointed by Generation and five by EDF. CENG was designed to operate under joint and equal control of Generation and EDFI through the Board of Directors, subject to the Chairman of the Board's final decision making authority on certain special matters; therefore, CENG was not subject to VIE guidance. Accordingly, Generation's 50.01% interest in CENG was accounted for as an equity method investment. On April 1, 2014, Generation, CENG, and subsidiaries of CENG executed the Nuclear Operating Services Agreement (NOSA) pursuant to which Generation now conducts all activities associated with the operations of the CENG fleet and provides corporate and administrative services to CENG and the CENG fleet for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDFI. As a result of executing the NOSA, CENG now qualifies as a VIE due to the disproportionate relationship between Generation's 50.01% equity ownership interest and its role in conducting the operational activities of CENG and the CENG fleet conveyed through the NOSA. Further, since Generation is conducting the operational activities of CENG and the CENG fleet, Generation qualifies as the primary beneficiary of CENG and, therefore, is required to consolidate the financial position and results of operations of CENG. On April 1, 2014, Exelon and Generation derecognized Generation's equity method investment in CENG and reflected all assets, liabilities, and the EDFI noncontrolling interest in CENG at fair value on the consolidated balance sheets of Exelon and Generation, resulting in the recognition of a $261 million gain in their respective consolidated statements of operations and comprehensive income for the nine months ended September 30, 2014. For additional information on this transaction refer to Note 6 — Investment in Constellation Energy Nuclear Group, LLC.

In March 2014, Generation began consolidating retail power VIEs for which Generation is the primary beneficiary as a result of energy supply contracts that give Generation the power to direct the activities that most significantly affect the economic performance of the entities. Generation does not have an equity ownership interest in these entities. These entities are included in Generation's consolidated financial statements, and the consolidation of the VIEs does not have a material impact on Generation's financial results or financial condition.

Consolidated Variable Interest Entities

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

- BondCo, a special purpose bankruptcy remote limited liability company formed by BGE to acquire, hold, and issue and service bonds secured by rate stabilization property,

- a retail gas group formed by Generation to enter into a collateralized gas supply agreement with a third-party gas supplier,
- a group of solar project limited liability companies formed by Generation to build, own and operate solar power facilities,
- several wind project companies designed by Generation to develop, construct and operate wind generation facilities,
- certain retail power companies for which Generation is the sole supplier of energy, and
- CENG.

As of September 30, 2014 and December 31, 2013, ComEd and PECO do not have any material consolidated VIEs.

As of September 30, 2014 and December 31, 2013, Exelon, Generation, and BGE provided the following support to their respective consolidated VIEs:

- In the case of BondCo, BGE is required to remit all payments it receives from all residential customers through non-bypassable, rate stabilization charges to BondCo. During the three and nine months ended September 30, 2014, BGE remitted $21 million and $63 million, respectively, to BondCo. During the three and nine months ended September 30, 2013, BGE remitted $24 million and $63 million, respectively, to BondCo.
- Generation provides operating and capital funding to the solar entities for ongoing construction, operations and maintenance of the solar power facilities and provides limited recourse related to the Antelope Valley project.
- Generation and Exelon, where indicated, provide the following support to CENG (see Note 25 — Related Party Transactions of the Exelon 2013 Form 10-K and Note 6 — Investment in Constellation Energy Nuclear Group, LLC for additional information regarding Generation 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 EDFI,
  - under the Power Services Agency Agreement (PSAA), Generation provides scheduling, asset management, and billing services to the CENG fleet for the remaining operating life of the CENG nuclear plants,
  - under power purchase agreements with CENG, Generation will purchase 85% of the available output generated by the CENG nuclear plants for the remainder of 2014 and 50.01% from 2015 through the end of the operating life of each respective plant,
  - Generation provided a $400 million loan to CENG (see Note 6 — Investment in Constellation Energy Nuclear Group, LLC for more details),
  - Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this Indemnity Agreement. (See Note 18 — Commitments and Contingencies for more details),

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

- in connection with CENG's severance obligations, Generation has agreed to reimburse CENG for a total of approximately $6 million of the severance benefits paid or to be paid in 2013 through 2016. As of September 30, 2014, the remaining obligation is approximately $4 million,
- Generation and EDFI share in the $637 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance (see Note 18 — Commitments and Contingencies for more details),
- Generation provides a guarantee of approximately $7 million associated with hazardous waste management facilities and underground storage tanks. In addition, EDFI executed a reimbursement agreement that provides reimbursement to Exelon for 49.99% of any amounts paid by Generation under this guarantee,
- Generation and EDFI are the members-insured with Nuclear Electric Insurance Limited and have assigned the loss benefits under the insurance and the NEIL premium costs to CENG and guarantee the obligations of CENG under these insurance programs in proportion to their respective member interests (see Note 18 — Commitments and Contingencies for more details), and
- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG's cash pooling agreement with its subsidiaries.

- Generation provides approximately $4 million in credit support for the retail power companies for which Generation is the sole supplier of energy, and
- Generation provides a $75 million parental guarantee to the third-party gas supplier in support of its retail gas group.

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 and BGE did not provide any additional material financial support to the VIEs;
- Exelon, Generation and BGE did not have any material contractual commitments or obligations to provide financial support to the VIEs; and
- the creditors of the VIEs did not have recourse to Exelon's, Generation's or BGE's general credit.

The carrying amounts and classification of the consolidated VIEs' assets and liabilities included in Exelon's, Generation's, and BGE's consolidated financial statements at September 30, 2014 and December 31, 2013 are as follows:

	September 30, 2014			December 31, 2013		
	Exelon[(a)(b)]	Generation[(b)]	BGE	Exelon[(a)]	Generation	BGE
Current assets	$ 1,071	$ 1,018	$ 47	$ 484	$ 446	$ 28
Noncurrent assets	7,384	7,367	3	1,905	1,884	3
Total assets	$ 8,455	$ 8,385	$ 50	$ 2,389	$ 2,330	$ 31
Current liabilities	$ 545	$ 460	$ 79	$ 566	$ 481	$ 74
Noncurrent liabilities	2,671	2,499	158	774	562	195
Total liabilities	$ 3,216	$ 2,959	$237	$ 1,340	$ 1,043	$269

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Includes total assets of $6.0 billion and total liabilities of $2.0 billion due to the consolidation of CENG beginning April 1, 2014. See Note 6 — Investment in Constellation Energy Nuclear Group, LLC for additional information.

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

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 September 30, 2014 and December 31, 2013, these assets and liabilities primarily consisted of the following:

	September 30, 2014			December 31, 2013		
	Exelon	Generation	BGE	Exelon	Generation	BGE
Cash and cash equivalents	$ 372	$ 372	$ —	$ 62	$ 62	$ —
Restricted cash	142	95	47	80	52	28
Accounts receivable, net						
Customer	213	213	—	260	260	—
Other	53	53	—	—	—	—
Mark-to-market derivatives assets	40	40	—	21	21	—
Inventory						
Materials and supplies	171	171	—	—	—	—
Other current assets	53	47	—	34	23	—
Total current assets	1,044	991	47	457	418	28
Property, plant and equipment, net	4,517	4,517	—	1,171	1,171	—
Nuclear decommissioning trust funds	2,034	2,034	—	—	—	—
Goodwill	46	46	—	—	—	—
Other noncurrent assets	132	115	3	127	106	3
Total noncurrent assets	6,729	6,712	3	1,298	1,277	3
Total assets	$7,773	$ 7,703	$ 50	$1,755	$ 1,695	$ 31
Short-term borrowings	$ 1	$ 1	$ —	$ —	$ —	$ —
Long-term debt due within one year	83	5	72	85	5	70
Accounts payable	264	264	—	170	170	—
Accrued expenses	78	72	7	26	22	4
Mark-to-market derivative liabilities	18	18	—	29	29	—
Other current liabilities	53	53	—	10	10	—
Total current liabilities	497	413	79	320	236	74
Long-term debt	256	84	158	298	86	195
Asset retirement obligations	1,654	1,654	—	—	—	—
Pension obligation[(a)]	8	8	—	—	—	—
Other noncurrent liabilities	179	179	—	40	40	—
Noncurrent liabilities	2,097	1,925	158	338	126	195
Total liabilities	$2,594	$ 2,338	$237	$ 658	$ 362	$269

(a) Includes the CNEG retail gas' pension obligation, which is presented as a net asset balance within the Prepaid Pension asset line item on Generation's balance sheet. See Note — 13 - Retirement Benefits for additional details.

Unconsolidated Variable Interest Entities

Exelon's and Generation's variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected on Exelon's and Generation's Consolidated Balance Sheets in Investments in affiliates, Investments, and Other assets. For the energy purchase and sale contracts and the fuel purchase commitments (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.

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

The Registrants' unconsolidated VIEs consist of:

- Energy purchase and sale agreements with VIEs for which Generation has concluded that consolidation is not required.
- ZionSolutions, LLC asset sale agreement with EnergySolutions, Inc. and certain subsidiaries in which Generation has a variable interest but has concluded that consolidation is not required.
- Equity investments in energy development projects and energy generating facilities for which Generation has concluded that consolidation is not required.

As of September 30, 2014 and December 31, 2013, Exelon and Generation had significant unconsolidated variable interests in eight VIEs for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity method investments and certain commercial agreements. The number of unconsolidated VIEs did not change overall; however, during the nine months ended September 30, 2014 Generation made an investment in a new unconsolidated VIE and executed an energy purchase and sale agreement with a new unconsolidated VIE, offset by the sale of Generation's ownership interest in two unconsolidated VIEs. The following tables present summary information about Exelon and Generation's significant unconsolidated VIE entities:

September 30, 2014	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[a]	$ 115	$ 307	$422
Total liabilities[a]	2	115	117
Exelon's ownership interest in VIE[a]	—	62	62
Other ownership interests in VIE[a]	113	130	243
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	66	66
Contract intangible asset	9	—	9
Debt and payment guarantees	—	3	3
Net assets pledged for Zion Station decommissioning[b]	31	—	31

December 31, 2013	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[a]	$ 128	$ 332	$460
Total liabilities[a]	17	123	140
Exelon's ownership interest in VIE[a]	—	86	86
Other ownership interests in VIE[a]	111	123	234
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	7	67	74
Contract intangible asset	9	—	9
Debt and payment guarantees	—	5	5
Net assets pledged for Zion Station decommissioning[b]	44	—	44

(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 $365 million and $458 million as of September 30, 2014 and December 31, 2013, respectively; offset by payables to ZionSolutions LLC of $334 million and $414 million as of September 30, 2014 and December 31, 2013, 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 assess 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

Proposed Merger with Pepco Holdings, Inc. (Exelon)

Description of Transaction

On April 29, 2014, Exelon and Pepco Holdings, Inc. (PHI) signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. Under the Merger Agreement, PHI's shareholders will receive $27.25 of cash in exchange for each share of PHI common stock. In connection with the Merger Agreement, Exelon entered into a subscription agreement under which it purchased $90 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities of PHI, in the second quarter of 2014, with additional investments of $18 million to be made quarterly up to a maximum aggregate investment of $180 million. PHI has the right to redeem the preferred securities at its option for the purchase price paid plus accrued dividends, if any. The $108 million of PHI preferred securities are included in Other non-current assets on Exelon's Consolidated Balance Sheet as of September 30, 2014. Exelon expects total cash required to fund the acquisition of common stock and preferred securities plus other related acquisition costs to total approximately $7.2 billion.

On September 23, 2014, PHI stockholders overwhelmingly approved the merger of PHI and Exelon. Completion of the transaction is also conditioned upon approval by the FERC and the public service commissions of the District of Columbia, Delaware, New Jersey and Virginia. Under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act), the transaction cannot be completed until Exelon has made required notifications and given certain information and materials to the Antitrust Division of the DOJ and until specified waiting period requirements have expired. In addition, the transfer of certain PHI communications licenses requires approval by the Federal Communication Commission.

During the second quarter of 2014, Exelon and PHI ("Joint Applicants") filed approval applications with the FERC and the public service commissions of the District of Columbia, Delaware, New Jersey and Virginia. On August 19, 2014, the Joint Applicants filed their approval application in Maryland. The Joint Applicants also filed notifications with the DOJ in compliance with the requirements of the HSR Act. Exelon's notification was voluntarily withdrawn and refiled in the third quarter.

On October 7, 2014, the Virginia State Corporation Commission issued its Order, granting approval to transfer control of Delmarva Power & Light Company and Potomac Electric Power Company to Exelon. FERC approval is expected in the fourth quarter of 2014, while procedural schedules have been set in the remaining state commission proceedings and final approval decisions are expected in the first half of 2015.

On October 9, 2014, PHI and Exelon each received a request for additional information from the DOJ. The request has the effect of extending the DOJ review period until 30 days after PHI and Exelon each has certified that it has substantially complied with the request. Exelon and PHI will continue to work cooperatively with the DOJ as it conducts its review of the proposed merger.

Exelon and PHI continue to expect to complete the merger in the second or third quarter of 2015.

Exelon has been named in suits filed in the Delaware Chancery Court alleging that individual directors of PHI breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors' breaches. The suits seek to enjoin PHI from completing the merger or seek rescission of the merger if completed. In addition, they also seek unspecified damages and costs. In September 2014, the parties reached a proposed settlement which is subject to court approval. Final court approval of the proposed settlement is not expected to occur until the second quarter of 2015, at the earliest. Exelon has also been named in a federal court case with similar claims and is in the process of negotiating a settlement. Exelon intends to vigorously defend these suits. Exelon does not believe these suits will impact the completion of the transaction, and they are not expected to have a material impact on Exelon's results of operations.

Through September 30, 2014, Exelon has incurred approximately $57 million of expense associated with the transaction, primarily related to acquisition and integration costs. As part of the applications for approval of the merger, Exelon and PHI have proposed a package of benefits to the PHI utilities' respective customers, which would result in a direct investment of more than $100 million. The Merger Agreement also provides for termination rights on behalf of both parties. Under certain circumstances, if the Merger Agreement is terminated, PHI may be required to pay Exelon a termination fee ranging from $259 million to $293 million plus certain expenses. If the Merger Agreement does not close due to a regulatory failure, Exelon may be required to pay PHI a termination fee equal to the amount of purchased nonvoting preferred securities of PHI described above, as a result of PHI redeeming the outstanding nonvoting preferred securities for no consideration other than the nominal par value of the stock.

Merger Financing

Exelon intends to fund the all-cash transaction using a combination of approximately $3.5 billion of debt, up to $1.0 billion in cash from asset sales primarily at Generation, and the remainder through issuance of equity (including mandatory convertible securities). On June 11, 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of $35 per share in connection with forward sales agreements and $1.2 billion of junior subordinated notes in the form of 23 million equity units. In addition, Exelon signed a 364-day $7.2 billion senior unsecured bridge credit facility to support the contemplated transaction and provide flexibility for timing of permanent financing, which has subsequently been reduced to a $3.9 billion facility as a result of the equity issuances and applicable asset divestitures. See Note 10 — Debt and Credit Agreements and Note 16 — Common Stock for more information.

Integrys Energy Group, Inc. (Exelon and Generation)

On July 29, 2014, Generation entered into a Stock Purchase Agreement (the Purchase Agreement) with Integrys Energy Group, Inc. (Integrys). Pursuant to the Purchase Agreement, Integrys agreed to sell its competitive retail electric and natural gas businesses through a sale of all of the stock of its wholly-owned subsidiary, Integrys Energy Services, Inc. (IES), to Generation for an all cash purchase price of $60 million plus adjusted net working capital at the time of the closing. IES's adjusted net working capital balance was approximately $260 million as of September 30, 2014. Pursuant to the Purchase Agreement, Generation has agreed to use its commercially reasonable efforts to replace the guarantees and other credit support currently being provided by Integrys for IES in support of the ongoing competitive retail businesses and to reimburse Integrys for any payments arising pursuant to such arrangements continuing for any post-closing period. The generation and solar asset businesses of IES are excluded from the transaction.

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

The transaction is expected to close November 1, 2014. The closing of the transaction is subject to certain conditions, including, among others, approval by the FERC and expiration or termination of the applicable waiting period under the HSR Act. The FERC approved the sale of IES to Exelon on September 16, 2014; additionally, the DOJ granted early termination of the HSR Act waiting period effective October 10, 2014. Either party may terminate the Purchase Agreement if the transaction has not been consummated within 6 months after the date of the Purchase Agreement. The Purchase Agreement also includes various representations, warranties, covenants, indemnification and other provisions customary for a transaction of this nature. The total costs directly related to the closing of the transaction are not expected to have a material impact on the financial results of Exelon and Generation.

Asset Divestitures (Exelon and Generation)

As of September 30, 2014, Generation had entered into agreements with various counterparties to divest certain generating assets with total expected pre-tax proceeds of $1.3 billion (approximately $975 million after-tax) which are expected to be used primarily to finance a portion of the acquisition of PHI. The net book value of these assets was approximately $900 million.

On August 8, 2014 Generation closed on the sale of its 67% economic equity interest in the 417 MW Safe Harbor Water Power Corporation hydroelectric facility on the Susquehanna River in Pennsylvania for a purchase price of approximately $615 million. Generation recorded a pre-tax gain on the sale of approximately $329 million within Other, net on Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income.

During the third quarter of 2014, Generation also entered into purchase and sale agreements with separate counterparties to divest the following long-lived assets:

Station	Net Generation Capacity	Location	Operating Segment
Fore River	726 MW	North Weymouth, MA	New England
West Valley	185 MW	Salt Lake City, UT	Other
Quail Run	488 MW	Odessa, TX	ERCOT

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

The assets and liabilities of the three power plants are reported as Assets held for sale and within Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets. The table below presents the major classes of assets and liabilities held for sale at September 30, 2014.

	September 30, 2014
Assets:	
Property, plant and equipment, net[a]	$ 617
Inventory	31
Current assets	1
Total assets held for sale	$ 649
Liabilities:	
Accounts payable	$ 1
Accrued expenses	4
Other current liabilities	13
Total liabilities held for sale [b]	$ 18

(a) The total aggregate book value of property, plant and equipment is net of a $50 million pre-tax impairment loss recorded within Operating and maintenance expense on Exelon's and Generation's Statements of Operations and Comprehensive Income. See Note 7 — Impairment of Long-Lived Assets for further information.
(b) Included within Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

The transactions, which are subject to customary closing conditions and regulatory approvals, are expected to be completed by the end of the first quarter of 2015.

5. Regulatory Matters (Exelon, Generation, ComEd, PECO and BGE)

Regulatory and Legislative Proceedings (Exelon, Generation, ComEd, PECO and BGE)

Except for the matters noted below, the disclosures set forth in Note 3 — Regulatory Matters of the Exelon 2013 Form 10-K appropriately represent, in all material respects, the current status of regulatory and legislative proceedings of the Registrants. The following is an update to that discussion.

Illinois Regulatory Matters

Energy Infrastructure Modernization Act (Exelon and ComEd). Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement(s) in effect for the prior year and actual costs incurred for that year. ComEd's earned rate of return on common equity is required to be within plus or minus 50 basis points ("the collar") of the target rate of return determined as the annual average rate on 30-year treasury notes plus 580 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on distribution revenue. In addition, ComEd's target rate of return on common equity is subject to reduction if ComEd does not deliver the reliability and customer service benefits, as defined, it has committed to over the ten-year life of the investment program. ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation. As of September 30, 2014, and December 31, 2013, ComEd had recorded a net regulatory asset associated with the distribution formula rate of $466 million and $463 million, respectively. The regulatory asset associated with the distribution true-up will be amortized as the associated amounts are recovered through rates.

On April 16, 2014, ComEd filed its annual distribution formula rate update with the ICC. The filing establishes the revenue requirement used to set the rates that will take effect in January 2015 after the ICC's review and approval, which is due by December 2014. The revenue requirement requested is based on 2013 actual costs plus projected 2014 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2013 to the actual costs incurred that year. ComEd's 2014 filing request includes a total increase to the net revenue requirement of $269 million, reflecting an increase of $174 million for the initial revenue requirement for 2014 and an increase of $95 million related to the annual reconciliation for 2013. The revenue requirement for 2014 provides for a weighted average debt and equity return on distribution rate base of 7.06% inclusive of an allowed return on common equity of 9.25%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2013 provided for a weighted average debt and equity return on distribution rate base of 7.04% inclusive of an allowed return on common equity of 9.20%, reflecting the average rate on 30-year treasury notes plus 580 basis points less a performance metrics penalty of 5 basis points.

On October 15, 2014, the ALJ issued its proposed order in ComEd's current distribution formula rate proceeding, recommending an increase to the net revenue requirement of $239 million as compared to ComEd's request of $269 million discussed above. The $30 million reduction, a portion of which may be recoverable through other recovery mechanisms, consisted of a decrease of $20 million for the initial revenue requirement for 2014 and a decrease of $10 million related to the annual reconciliation for 2013. The ALJs proposed order has no independent legal effect as the ICC must vote on a final order by mid December 2014, which may materially vary from the findings and conclusions in the proposed order. If the ICC provides significant changes to ComEd's filed revenue requirement request, it could have a material impact on ComEd's current and future results of operations and cash flows.

EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. Participating utilities are required to file an annual update on their AMI implementation progress. On April 1, 2014, ComEd filed an annual progress report on its AMI Implementation Plan with the ICC. The ICC ruled that no investigation would be opened in regards to that April filing. In March 2014, ComEd filed a petition with the ICC for approval to accelerate the deployment of AMI meters. On June 11, 2014, the ICC approved ComEd's accelerated deployment plan which allows for the installation of more than four million smart meters throughout ComEd's service territory by 2018, three years in advance of the originally scheduled 2021 completion date. To date, nearly 500,000 smart meters have been installed in the Chicago area.

Appeal of the 2012 Formula Rate Tariff (Exelon and ComEd). On April 30, 2012, ComEd filed its annual distribution formula rate update. The filing established the revenue requirement used to set the rates that were effective in January 2013. On December 20, 2012, the ICC issued its final order, which increased the revenue requirement by $73 million. The $73 million reflected an increase of $80 million for the initial revenue requirement for 2012 and a decrease of $7 million for the annual reconciliation for 2011. The rate increase was set using an allowed return on capital of 7.54% (inclusive of an allowed return on common equity of 9.81%). The rates took effect in January 2013. ComEd and intervenors requested a rehearing on specific issues, which was denied by the ICC. ComEd and intervenors also filed appeals with the Illinois Appellate Court.

On June 30, 2014, the Illinois Appellate Court issued its opinion, finding against ComEd on two issues and for ComEd on a third issue. The two issues (billing determinants and the use of certain allocators) were the same issues previously rejected by the Court in the Appeal of Initial Formula Rate Tariff (see Appeal of Initial

Formula Rate Tariff discussed below). The Court re-affirmed the ICC's order and rejected ComEd's arguments. However, on the third issue (rate case expenses), the Court allowed for the possibility of future recovery. The Court's opinion has no accounting impact as ComEd recorded the distribution formula regulatory asset consistent with the ICC's final Order.

Appeal of Initial Formula Rate Tariff (Exelon and ComEd). On March 26, 2014, the Illinois Appellate Court issued an opinion with respect to ComEd's appeal of the ICC's order relating to ComEd's initial formula rate tariff. The most significant financial issues under appeal related to ICC findings that were counter to the formula rate legislation and were clarified by subsequent legislation (Senate Bill 9). Therefore, only a subset of the issues originally appealed remained. The Court found against ComEd on each of the remaining issues: compensation related adjustments, billing determinants and the use of certain allocators. The Court's opinion has no accounting impact as ComEd recorded the distribution formula regulatory asset consistent with the ICC's final Order.

ComEd has asked the Illinois Supreme Court to hear the issue of allocation between State and Federal regulatory jurisdictions. On June 4, 2014, ComEd filed a Petition for Leave to Appeal with the Illinois Supreme Court solely on the issue of allocation between FERC and ICC jurisdictional costs. On July 2, 2014, the ICC filed its Answer to the Petition, arguing that Supreme Court review is not necessary or appropriate. Under the procedural rules of the Illinois Supreme Court, ComEd is not allowed to reply to the ICC filing. There is no set time by which the Court must rule on the Petition. ComEd cannot predict whether the Court will grant the appeal, or if it does, the ultimate outcome.

Appeal of 2007 Illinois Electric Distribution Rate Case (Exelon and ComEd). The ICC issued an order in ComEd's 2007 electric distribution rate case (2007 Rate Case) approving a $274 million increase in ComEd's annual delivery services revenue requirement, which became effective in September 2008. In the order, the ICC authorized a 10.3% rate of return on common equity. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). The Court issued a decision on September 30, 2010, ruling against ComEd on the treatment of post-test year accumulated depreciation and the recovery of system modernization costs via a rider (Rider SMP).

The court held the ICC abused its discretion in not reducing ComEd's rate base to account for an additional 18 months of accumulated depreciation while including post-test year pro forma plant additions through that period. ComEd continued to bill rates as established under the ICC's order in the 2007 Rate Case until June 1, 2011 when the rates set in the 2010 electric distribution rate case became effective. In subsequent ICC proceedings, the ICC issued an order requiring ComEd to provide a refund of approximately $37 million to customers related to the treatment of post-test year accumulated depreciation issue. On March 26, 2012, ComEd filed a notice of appeal with the Court.

However, on September 27, 2013, the Court ruled against ComEd on the accumulated depreciation issue and affirmed that ComEd owes a refund to customers of approximately $37 million, including interest. On September 18, 2014, the ICC issued an order which modified the timing of the refund, now to occur in November 2014, rather than the eight month period previously approved. The refund will be included with the Rider AMP refund discussed below. Former ComEd customers also are eligible for a refund. As of September 30, 2014, and December 31, 2013, ComEd had fully reserved for this liability.

Advanced Metering Program Proceeding (Exelon and ComEd). As part of ComEd's 2007 Rate Case, the ICC approved recovery of costs associated with ComEd's Rider SMP for the limited purpose of implementing a pilot program for AMI. In October 2009, the ICC approved ComEd's AMI pilot program and associated rider

(Rider AMP). ComEd collected approximately $24 million under Rider AMP and had no collections under Rider SMP through September 30, 2014. In ComEd's 2010 electric distribution rate case, the ICC approved ComEd's transfer of certain other costs from recovery under Rider AMP to recovery through electric distribution rates.

Several parties, including the Illinois Attorney General, appealed the ICC's orders on Rider SMP and Rider AMP. The Illinois Appellate Court reversed the ICC's approval of the cost recovery provisions of Rider SMP and Rider AMP on September 30, 2010 and March 19, 2012, respectively. In both cases, the Court ruled that the ICC's approval of the rider constituted single-issue ratemaking. ComEd filed Petitions for Leave to Appeal to the Illinois Supreme Court, which were denied.

In October 2013, the ICC opened an investigation on Rider AMP to determine if a refund is required and if so, to determine the appropriate refund amount. The ALJ presiding over the investigation requested each party provide a pre-trial memorandum describing their positions, which were submitted on April 10, 2014. The ICC Staff and the Illinois Attorney General proposed a refund of $14.6 million, representing the amount they claim was collected under Rider AMP since September 30, 2010, the date the Illinois Appellate Court reversed the ICC's approval of the cost recovery provisions of Rider SMP. ComEd believes no refund is appropriate and that any refund obligation associated with Rider AMP should be prospective from no earlier than the date of the Illinois Appellate Court's order on Rider AMP, or March 19, 2012, which would represent a refund of approximately $0.4 million. During the second quarter of 2014, ComEd reached a tentative agreement to jointly resolve the disputed refund claim. On September 18, 2014, the ICC approved a refund of $9.5 million plus interest to be issued to current customers in November 2014. Former ComEd customers also are eligible for a refund. As of September 30, 2014, ComEd had fully reserved for this liability.

Grand Prairie Gateway Transmission Line (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 May 28, 2014, in a separate proceeding, FERC issued an order granting ComEd's request to include 100% of the capital costs recorded to construction work in progress during construction of the line in ComEd's transmission rate base. If the project is cancelled or abandoned for reasons beyond ComEd's control, FERC approved the ability for ComEd to recover 100% of its prudent costs incurred after May 21, 2014 and 50% of its costs incurred prior to May 21, 2014 in ComEd's transmission rate base. On October 22, 2014, the ICC issued an order approving ComEd's Grand Prairie Gateway Project over the objection of numerous landowners and the City of Elgin. Those parties now have 30 days to request that the ICC reconsider its decision and subsequently file an appeal with the Illinois Appellate Court. ComEd expects to begin construction of the line in the second quarter of 2015 with an in service date expected in the second quarter of 2017.

Illinois Procurement Proceedings (Exelon, Generation and ComEd). ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Since June 2009, as a result of the Illinois Settlement Legislation, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. On December 18, 2013, the ICC approved the IPA's procurement plan covering the period June 2014 through May 2019.

The Illinois Settlement Legislation requires ComEd to purchase an increasing percentage of the electricity for customer deliveries from renewable energy resources. Purchases by customers of electricity from competitive generation suppliers, whether as a result of the customers' own actions or as a result of municipal aggregation, are not included in this calculation and have the effect of reducing ComEd's purchase obligation. ComEd entered into several 20-year contracts with unaffiliated suppliers in December 2010 regarding the procurement of long-term renewable energy and associated RECs in order to meet its obligations under the state's RPS. Under the

Illinois Settlement Legislation, all associated costs are recoverable from customers. The ICC did not require the acquisition of additional renewable resources for the period June 2014 through May 2015 due to ComEd expecting to exceed the renewable cost cap established by the Illinois Settlement Legislation.

The IPA's 2014-2019 plan provides for two separate energy procurements during 2014 to address potential fluctuations in energy demand due to customer switching between ComEd and competitive electric generation suppliers. The ICC also approved the IPA's expansion of energy efficiency programs for both ComEd and Ameren. As of September 30, 2014, ComEd has completed both of the scheduled 2014 energy procurements, which cover a portion of its energy requirements through the periods ending May 31, 2015, 2016 and 2017. See Note 18 — Commitments and Contingencies for additional information on ComEd's energy commitments.

FutureGen Industrial Alliance, Inc (Exelon and ComEd). During 2013, the ICC approved and directed ComEd and Ameren to enter into a 20-year sourcing agreement with FutureGen Industrial Alliance, Inc. (FutureGen), under which FutureGen will retrofit and repower an existing plant in Morgan County, Illinois to a 166 MW near zero emissions coal-fueled generation plant, with an assumed commercial operation date in 2017. The sourcing agreement provides that ComEd and Ameren will pay FutureGen's contract prices, which are set annually pursuant to a formula rate. The contract prices are based on the difference between the costs of the facility and the revenues FutureGen receives from selling capacity and energy from the unit into the MISO or other markets, as well as any other revenue FutureGen receives from the operation of the facility. The order also directs ComEd and Ameren to recover these costs from their electric distribution customers through the use of a tariff, regardless of whether they purchase electricity from ComEd or Ameren, or from competitive electric generation suppliers.

In February 2013, ComEd filed an appeal with the Illinois Appellate Court questioning the legality of requiring ComEd to procure power for retail customers purchasing electricity from competitive electric generation suppliers. On July 22, 2014, the Illinois Appellate Court issued its ruling re-affirming the ICC's order requiring ComEd to enter into the sourcing agreement with FutureGen and allowing the use of a tariff to recover its costs. ComEd decided not to appeal the Illinois Appellate Court's decision to the Illinois Supreme Court. However, the competitive electric generation suppliers have reserved their right to appeal the Illinois Appellate Court's decision.

ComEd executed the sourcing agreement with FutureGen in accordance with the ICC's order. In addition, ComEd filed a petition with the ICC seeking approval of the tariff allowing for the recovery of its costs associated with the FutureGen contract from all of its electric distribution customers, which was approved by the ICC on September 30, 2014. Depending on eventual market conditions and the cost of the facility, the sourcing agreement could have a material adverse impact on Exelon's and ComEd's cash flows and financial positions.

Pennsylvania Regulatory Matters

Pennsylvania Procurement Proceedings (Exelon and PECO). On October 12, 2012, the PAPUC issued its Opinion and Order approving PECO's second DSP Program, which was filed with the PAPUC in January 2012. The program, which has a 24-month term from June 1, 2013 through May 31, 2015, complies with electric generation procurement guidelines set forth in Act 129.

In the second DSP Program, PECO is procuring electric supply for its default electric customers through five competitive procurements. The load for the residential and small and medium commercial classes is served through competitively procured fixed price, full requirements contracts of two years or less. For the large commercial and industrial class load, PECO has competitively procured contracts for full requirements default electric generation with the price for energy in each contract set to be the hourly price of the spot market during the term of delivery. In December 2012 and February 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential class and its small and medium commercial classes that began in June 2013. In September 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential class and its small and medium commercial classes that began in December 2013. In January 2014, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential class and its and small, medium, and large commercial classes that began in June 2014. In September 2014, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its final competitive procurements of electric supply for its residential class and its small and medium commercial classes commencing December 2014. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO’s Statement of Operations and Comprehensive Income.

In addition, the second DSP Program includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to submit a plan to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from EGSs beginning April 2014. On May 1, 2013, PECO filed its CAP Shopping Plan with the PAPUC. By Order entered on January 24, 2014, the PAPUC approved PECO’s plan, with modifications, to make CAP shopping available beginning April 15, 2014. On March 20, 2014, low-income advocacy groups filed an appeal and emergency request for a stay with the Pennsylvania Commonwealth Court, claiming that the PAPUC-ordered CAP Shopping plan does not contain sufficient protections for low-income customers. On March 28, 2014, the Commonwealth Court issued the requested stay, pending a full review of the appeal. Pending the Commonwealth Court’s review, PECO will not implement CAP Shopping. The Commonwealth Court’s decision is expected in early 2015.

On March 10, 2014, PECO filed its third DSP Program with the PAPUC. The program has a 24-month term from June 1, 2015 through May 31, 2017, and complies with electric generation procurement guidelines set forth in Act 129. On August 28, 2014, PECO filed a Joint Petition for Partial Settlement, which affirmed PECO’s procurement plan for Residential and Small Commercial customers and reserved two issues for litigation: certain non-bypassable transmission charges and the default service product for Medium Commercial customers (including hourly pricing). On September 30, 2014, the ALJ issued a Recommended Decision to the PAPUC that PECO’s third DSP Program be approved, as modified by the Joint Petition for Partial Settlement, but also recommending that the Large C&I class should be excluded from the recommended non-bypassable charge for non-market-based charges. A final ruling from the PAPUC is expected by December 2014.

Smart Meter and Smart Grid Investments (Exelon and PECO). Pursuant to Act 129 and the follow-on Implementation Order of 2009, in April 2010, the PAPUC approved PECO’s Smart Meter Procurement and Installation Plan (SMPIP), under which PECO will install more than 1.6 million smart meters and an AMI communication network by 2020. The first phase of PECO’s SMPIP, which was completed on June 19, 2013, included the installation of an AMI communications network and the deployment of 600,000 smart meters to communicate with that network. On May 31, 2013, PECO and interested parties filed a Joint Petition for Settlement of the universal deployment plan with the PAPUC which was approved without modification on August 15, 2013. The Joint Petition for Settlement supports all material aspects of PECO’s universal deployment plan, including cost recovery, excluding certain amounts discussed below. Universal deployment is the second phase of PECO’s SMPIP, under which PECO will deploy substantially all of the 1.6 million smart meters on an accelerated basis by the end of 2014. In total, PECO currently expects to spend up to $595 million, excluding the cost of the original meters (as further described below), on its smart meter infrastructure and approximately $120 million on smart grid investments through 2014 of which $200 million will be funded by SGIG as discussed below. As of September 30, 2014, PECO has spent $516 million and $119 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received to date.

Pursuant to the ARRA of 2009, PECO and the DOE entered into a Financial Assistance Agreement to extend PECO $200 million in non-taxable SGIG funds of which $140 million relates to smart meter deployment and $60 million relates to smart grid infrastructure. As part of the agreement, the DOE has a conditional ownership interest in qualifying Federally-funded project property and equipment, which is subordinate to PECO’s existing mortgage. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. As of September 30, 2014, PECO has received substantially all of the $200 million, including $4 million for sub-recipients, in reimbursements. On October 15, 2014, the DOE issued a Close Out of Post-Award Project Cost Verification Audit, in which it was determined that PECO fully met its required cost share, and the audit was closed with no further action required.

On August 15, 2012, PECO suspended installation of smart meters for new customers based on a limited number of incidents involving overheating meters. Following its own internal investigation and additional scientific analysis and testing by independent experts completed after September 30, 2012, PECO announced its decision to resume meter deployment work on October 9, 2012. PECO has replaced the previously installed meters with an alternative vendor’s meters. PECO is moving forward with the alternative meters during universal deployment and continues to evaluate meters from several vendors and may use more than one meter vendor during universal deployment.

Following PECO’s decision, as of October 9, 2012, PECO will no longer use the original smart meters. For the meters that will no longer be used, the accounting guidance requires that any difference between the carrying value and net realizable value be recognized in the current period’s earnings, before considering potential regulatory recovery. The cost of the original meters, including installation and removal costs, owned by PECO was approximately $17 million, net of approximately $16 million of reimbursements from the DOE and approximately $2 million of depreciation. PECO requested and received approval from the DOE that the original meters continued to be allowable costs and that any settlement with the vendor would not be considered project income. In addition, PECO remains eligible for the full $200 million in SGIG funds. On August 15, 2013, PECO entered into an agreement with the original vendor, which was part of the final agreement discussed below, under which PECO transferred the original uninstalled meters to the vendor and received $12 million in return. On January 23, 2014, PECO entered a final agreement with the vendor pursuant to which PECO will be reimbursed for amounts incurred for the original meters and related installation and removal costs, via cash payments and rebates on future purchases of licenses, goods and services primarily through 2017. PECO previously had intended to seek regulatory rate recovery in a future filing with the PAPUC of amounts not recovered from the vendor. As PECO believed such costs were probable of rate recovery based on applicable case law and past precedent on reasonably and prudently incurred costs, a regulatory asset was established at the time of the removals. As of December 31, 2013, $5 million was recorded on Exelon’s and PECO’s Consolidated Balance Sheets. Pursuant to the January 23, 2014, vendor agreement, PECO reclassified the regulatory asset balance as a receivable, which was fully collected as of September 30, 2014, with no gain or loss impacts on future results of operations. On March 14, 2014, PECO filed its quarterly smart meter recovery surcharge with the PAPUC, which included PECO’s proposed treatment of the final agreement with the vendor. On March 27, 2014, the PAPUC approved the surcharge as proposed by PECO.

Energy Efficiency Programs (Exelon and PECO). PECO’s PAPUC-approved Phase I EE&C Plan had a four-year term that began on June 1, 2009 and concluded on May 31, 2013. The Phase I Plan set forth how PECO would meet the required reduction targets established by Act 129’s EE&C provisions, which included a 3% reduction in electric consumption in PECO’s service territory and a 4.5% reduction in PECO’s annual system peak demand in the 100 hours of highest demand by May 31, 2013.

PECO filed its final compliance report on Phase 1 targets with the PAPUC on November 15, 2013. On March 20, 2014, the PAPUC issued its final report stating that PECO was in full compliance with all Phase I targets.

On November 14, 2013, the PAPUC issued a Tentative Order on Act 129 demand reduction programs which seeks comments on a proposed demand response program methodology for future Act 129 demand reduction programs as well as demand response potential and wholesale prices suppression studies. In its February 20, 2014 Final Order, the PAPUC stated that it does not expect to make a decision as to whether it will prescribe additional demand response obligations until 2015. Any decision reached would affect PECO's EE&C Plan subsequent to its Phase II Plan.

On February 28, 2014, PECO filed a Petition for Approval to amend its EE&C Phase II Plan to continue its DLC demand reduction program for mass market customers from June 1, 2014 to May 31, 2016. PECO proposed to fund the estimated $10 million annual costs of the program by modifying incentive levels for other Phase II programs. The costs of the DLC program will be recovered through PECO's Energy Efficiency Program Charge along with other Phase II Plan costs. In an April 23, 2014 Tentative Order, the PAPUC granted PECO's Petition. The Order became final on May 5, 2014.

Pennsylvania Retail Electricity Market (Exelon and PECO). The extreme weather experienced in early 2014 resulted in increased commodity costs causing certain shopping customers to receive unexpectedly high utility bills. In response to a significant number of customer complaints throughout Pennsylvania, on April 3, 2014, the PAPUC unanimously voted to adopt two rulemaking orders to address the issue. The first rulemaking order requires electric generation suppliers to provide more consumer education regarding their contract. The second rulemaking order requires electric distribution companies to enable customers to switch suppliers within three business days (known as accelerated switching). The improved customer education and accelerated switching are to be in place within 30 days and six months of approval of the orders, respectively. The Independent Regulatory Review Commission granted approval of the orders on May 22, 2014. The orders became final on June 14, 2014. PECO is in process of implementing compliance with the order.

Maryland Regulatory Matters

2014 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 2, 2014, BGE filed an application for increases of $118 million and $68 million to its electric and gas base rates, respectively, with the MDPSC. The requested rates of return on equity in the application were 10.65% and 10.55% for electric and gas distribution, respectively. On September 15, 2014, BGE filed an update to its rate request which altered the requested increase to electric base rates from $118 million to $99 million. The requested increase to gas base rates did not change.

On October 17, 2014, BGE filed with the MDPSC a unanimous settlement agreement (the Settlement Agreement) reached with all parties to the case under which it would receive an increase of $22 million in electric base rates and an increase of $38 million in gas base rates. The Settlement Agreement establishes new depreciation rates which have the effect of decreasing annual depreciation expense by approximately $20 million, primarily for electric. The Settlement Agreement remains subject to MDPSC approval. If approved by the MDPSC, rates would go into effect no sooner than December 15, 2014, and no later than late January 2015. BGE is uncertain if the MDPSC will unconditionally approve the Settlement Agreement or if further proceedings will be required.

2013 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On May 17, 2013, BGE filed an application for increases of $101 million and $30 million to its electric and gas base rates, respectively, with the MDPSC. The requested rates of return on equity in the application were 10.50% and 10.35% for electric and gas distribution, respectively. In addition to these requested rate increases, BGE's application also included a request for recovery of incremental capital expenditures and operating costs associated with BGE's proposed short-term reliability improvement plan (the "ERI initiative") in response to a MDPSC order through a surcharge separate from base rates. On August 23, 2013, BGE filed an update to its rate request which altered the requested increase to electric base rates from $101 million to $83 million and the requested increase to gas base rates from $30 million to $24 million. On December 13, 2013, the MDPSC issued an order in BGE’s 2013 electric and natural gas distribution rate case for increases in annual distribution service revenue of $34 million and $12 million, respectively. The electric distribution rate increase was set using an allowed return on equity of 9.75% and the gas distribution rate increase was set using an allowed return on equity of 9.60%. The approved electric and natural gas distribution rates became effective for services rendered on or after December 13, 2013. As part of its December 13, 2013 decision granting BGE increases for its gas and electric distribution rates, the MDPSC also authorized BGE to recover through a surcharge mechanism costs associated with five ERI initiative programs designed to accelerate electric reliability improvements. Such a decision, however, was premised upon the condition that the MDPSC approve specific projects scheduled for each year of the five-year program in advance of cost recovery through the surcharge mechanism. On March 31, 2014, after reviewing comments filed by the parties and conducting a hearing on the matter, the MDPSC approved all but one project proposed for completion in 2014 as part of the ERI initiative. As a result of the MDPSC’s decision, BGE estimates 2014 capital and operating and maintenance costs associated with the ERI initiative of $14.8 million and a revenue requirement of $1.4 million. The ERI initiative surcharge became effective June 1, 2014. BGE is required to file an update on the 2014 work plan and reliability performance information for the specific projects, along with its work plan and cost estimates for 2015, on or before November 1, 2014.

In January 2014, the residential consumer advocate in Maryland filed an appeal to the order issued by the MDPSC on December 13, 2013 in BGE’s 2013 electric and gas distribution rate cases. The residential consumer advocate filed its related legal memorandum on August 22, 2014, challenging the MDPSC’s approval of the ERI initiative surcharge. BGE submitted a response to the appeal on October 15, 2014, and a hearing has been scheduled for November 17, 2014. BGE cannot predict the outcome of this appeal.

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of $480 million of which $200 million has been recovered through a grant from the DOE. 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 September 30, 2014 and December 31, 2013, BGE recorded a regulatory asset of $111 million and $66 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program. As part of the settlement in BGE’s 2014 electric and gas distribution rate case discussed above, the cost of the retired non-AMI meters will be amortized over 10 years. However, as discussed above, the settlement is still subject to MDPSC approval.

On February 26, 2014, the MDPSC issued an Order authorizing BGE to impose a $75 upfront fee and an $11 recurring fee to customers electing to opt-out of smart meter replacement, effective the later of the first full billing cycle following July 1, 2014, or the AMI installation date in a customer’s community. The fees authorized by the order will be reviewed after an initial 12 to 18 month period. As of September 30, 2014, BGE is awaiting the MDPSC’s decision regarding BGE’s proposal to automatically enroll unresponsive customers into the opt-out program. The proposal, if approved, would allow BGE to begin charging these customers opt-out fees. The ultimate impact of opt-out could affect BGE’s ability to demonstrate cost-effectiveness of the advanced metering system.

Overall, BGE continues to believe the recovery of smart grid initiative costs in future rates is probable as BGE expects to be able to demonstrate that the program benefits exceed costs.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to recover promptly reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. On May 2, 2013, the Governor of Maryland signed the legislation into law, which took effect June 1, 2013. Under the new law, following a proceeding before the MDPSC and with the MDPSC's approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. The legislation includes caps on the monthly surcharges to residential and non-residential customers, and would require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be included in gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and surcharge. On March 26, 2014, the Maryland PSC approved as filed BGE's proposed 2014 project list, tariff and associated surcharge amounts, with a surcharge that became effective April 1, 2014. BGE will defer the difference between the surcharge revenues and program costs as a regulated asset or liability, which was immaterial to BGE and Exelon as of September 30, 2014.

In February 2014, the residential consumer advocate in Maryland filed an appeal with the Baltimore City Circuit Court to the decision issued by the MDPSC on BGE's infrastructure replacement plan. The residential consumer advocate filed its related legal memorandum on July 7, 2014, claiming that the MDPSC did not apply the appropriate consideration in approving BGE's infrastructure replacement plan and associated surcharge. BGE submitted a response to the appeal on August 6, 2014. On September 5, 2014, the Baltimore City Circuit Court affirmed the MDPSC decision on BGE's infrastructure replacement plan and associated surcharge. On October 10, 2014, the residential consumer advocate noticed its appeal to the Maryland Court of Special Appeals from the judgment entered by the Baltimore City Circuit Court.

Federal Regulatory Matters

Transmission Formula Rate (Exelon, ComEd and BGE). ComEd's and BGE's transmission rates are each established based on a FERC-approved formula. ComEd and BGE record regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement in effect and ComEd's and BGE's best estimate of the revenue requirement expected to be approved by the FERC for that year's reconciliation. As of September 30, 2014 and December 31, 2013, ComEd had recorded a net regulatory asset associated with the transmission formula rate of $19 million and $17 million, respectively. BGE recorded a net regulatory asset associated with the transmission formula rate of $3 million at September 30, 2014, and a net regulatory liability which was not material as of December 31, 2013. The regulatory asset associated with the transmission true-up will be amortized as the associated amounts are recovered through rates.

On April 16, 2014, ComEd filed its annual formula rate update with the FERC. The filing establishes the revenue requirement used to set rates that took effect in June 2014, subject to review by the FERC and other parties, which is due by November 2014. The revenue requirement is based on 2013 actual costs plus forecasted 2014 capital additions as well as an annual reconciliation of the revenue requirement in effect starting in June 2013 to the actual cost incurred in 2013. The update resulted in a revenue requirement of $524 million plus an $11 million adjustment related to the reconciliation of 2013 actual costs for a total revenue requirement of $535 million. This compares to the 2013 revenue requirement of $488 million plus a $25 million adjustment related to the reconciliation of 2012 actual costs for a total revenue requirement of $513 million. The increase in the revenue requirement was primarily driven by increased capital investment and higher operating and maintenance costs.

ComEd's updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.62%, which is inclusive of an allowed return on common equity of 11.50%, a decrease from the 8.70% average debt and equity return previously authorized. 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%.

On April 28, 2014, BGE filed its annual formula rate update with the FERC. The filing established the revenue requirement used to set rates that took effect in June 2014, subject to review by the FERC and other parties, which is due by October 2014. The revenue requirement is based on 2013 actual costs plus forecasted 2014 capital additions as well as an annual reconciliation of the revenue requirement in effect starting in June 2013 to the actual cost incurred in 2013. The update resulted in a revenue requirement of $167 million plus a $4 million adjustment related to the reconciliation of 2013 actual costs for a total revenue requirement of $171 million. This compares to the 2013 revenue requirement of $158 million offset by a $1 million reduction related to the reconciliation of 2012 actual costs for a net revenue requirement of $157 million. The increase in the revenue requirement is primarily driven by higher depreciation expense and an increased level of return on investment associated with a higher equity ratio and increased rate base.

BGE's updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.53%, an increase from the 8.35% average debt and equity return previously authorized. As part of the FERC-approved settlement of BGE's 2005 transmission rate case in 2006, the rate of return on common equity for BGE's electric transmission business for new transmission projects placed in service on and after January 1, 2006 is 11.3%, which is inclusive of a 50 basis point incentive for participating in PJM.

FERC Transmission Complaint (Exelon and BGE). On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the PHI companies relating to their respective transmission formula rates. BGE's formula rate includes a 10.8% base rate of return on common equity (ROE) for most investments included in its rate base and 11.3% for the remaining transmission investment (the latter of which is conditioned upon crediting the first 50 basis points of any incentive ROE adders). The parties seek a reduction in the base return on equity to 8.7% and changes to the formula rate process. FERC docketed the matter and set April 3, 2013 as the deadline for interventions, protests and answers. Under FERC rules, the revenues subject to refund are limited to a fifteen month period, and the earliest date from which the base return on equity could be adjusted and refunds required is the date of the complaint. On March 19, 2013, BGE filed a motion to dismiss or sever the complaint. On June 19, 2014, FERC issued an order in another case involving New England Transmission Owners (NETOs), changing its methodology to determine ROE rates for public utilities. The result was a reduction in the NETO's ROE from 11.14% to 10.57%, with a possible further adjustment in either direction based on additional paper hearing submissions. On July 21, 2014, the NETOs filed a Request for Rehearing and Clarification with FERC of the June 19, 2014 order. Among other things, the NETOs assert that the 11.14% is reasonable based on the new methodology. Following the paper submissions, FERC again approved a base ROE of 10.57% on October 16, 2014.

On August 21, 2014, FERC issued an order in the BGE and PHI companies' proceeding, which established hearing and settlement judge procedures for the complaint, and set a refund effective date of February 27, 2013. BGE, the PHI companies and the parties began settlement discussions under the guidance of a FERC administrative law judge on September 23, 2014 and the discussions are expected to continue at least through November. While it is too early in the process to predict the outcome of the settlement discussions, if the parties cannot resolve their differences, the matter will proceed to hearing.

Based on the current status of the settlement discussions, BGE believes it is probable that BGE's base ROE rate will be adjusted, and that a refund to customers of transmission revenue for the maximum fifteen month period will be required. However, BGE is unable to estimate the most likely refund amount at this time, and has therefore established a reserve, which is not material, representing the low end of a reasonably possible estimated range of loss. If FERC were to order a reduction of BGE's base return on equity to 8.7% as sought in the original complaint (while retaining the 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment), the result would be a refund to customers of approximately $13 million, as well as an estimated ongoing annual reduction in revenues of approximately $10 million.

PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd, PECO and BGE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE 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. After FERC ultimately denied all requests for rehearing on all issues, several parties filed petitions in the U.S. Court of Appeals for the Seventh Circuit for review of the decision. On August 6, 2009, that court issued its decision affirming FERC's order with regard to the costs of existing facilities but reversing and remanding to FERC for further consideration its decision with regard to the costs of new facilities 500 kV and above. On March 30, 2012, FERC issued an order on remand affirming the cost allocation in its April 2007 order. On March 22, 2013, FERC issued an order denying rehearing and made it clear that the cost allocation at issue concerns only projects approved prior to February 1, 2013. A number of entities have filed appeals of the FERC orders. On June 25, 2014, the U.S. Court of Appeals for the Seventh Circuit issued a decision once again remanding to FERC the cost allocation of new facilities 500 kV and above. ComEd anticipates that all impacts of any rate design changes effective after December 31, 2006, should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on ComEd's results of operations, cash flows or financial position. PECO anticipates that all impacts of any rate design changes should be recoverable through the transmission service charge rider approved in PECO's 2010 electric distribution rate case settlement and, thus, the rate design changes are not expected to have a material impact on PECO's results of operations, cash flows or financial position. To the extent any rate design changes are retroactive to periods prior to January 1, 2011, there may be an impact on PECO's results of operations. BGE anticipates that all impacts of any rate design changes effective after the implementation of its standard offer service programs in Maryland should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on BGE's results of operations, cash flows or financial position.

PJM Minimum Offer Price Rule (Exelon and Generation). PJM's capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. The FERC orders approving the MOPR were upheld by the United States Court of Appeals for the Third Circuit in February 2014.

Exelon continues to work with PJM stakeholders and through the FERC process to implement several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sanctioned subsidy contracts and capacity market speculators) cannot inappropriately affect capacity auction prices in PJM.

Demand Response Resource Order (Exelon, Generation, ComEd, PECO, BGE). On May 23, 2014, the D.C. Circuit Court issued an opinion vacating the FERC Order No. 745 ("D.C. Circuit Decision"). Order No. 745 established uniform compensation levels for demand response resources that participate in the day ahead and real-time wholesale energy markets. Under Order No. 745, buyers in ISO and RTO markets were required to pay demand response resources the full Locational Marginal Price when the demand response replaced a generation resource and was cost-effective.

In addition to invalidating the compensation structure established by Order No. 745, the D.C. Circuit Court, in broad language, explained that demand response is part of the retail market and FERC is restricted from regulating retail markets. The full implication of the D.C. Circuit Decision for both energy and capacity markets regulated by FERC is not yet known and will depend on how FERC and the RTOs and ISOs implement the decision. FERC and several other parties sought rehearing of the D.C. Circuit Decision, which was denied in September 2014. In addition, on September 22, 2014, FERC and another party sought to stay the issuance of the D.C. Circuit Court's mandate so that FERC may determine whether to appeal the decision to the U.S. Supreme Court. Therefore, FERC will not be required to implement the D.C. Circuit Decision until a determination is made on the stay request. FERC and other parties will have until December 2014 to appeal the decision to the U.S. Supreme Court. FERC or other parties may also petition the U.S. Supreme Court to review the decision of the D.C. Circuit Court. In addition, contemporaneously with the D.C. Circuit Court's decision on May 23, 2014, First Energy filed a complaint at FERC asking FERC to direct PJM to remove all PJM Tariff provisions that allow or require PJM to compensate demand response providers as a form of supply in the PJM capacity market effective May 23, 2014. FirstEnergy also asked FERC to declare the results of PJM's May 2014 Base Residual Auction for the 2017/2018 Delivery Year, void and illegal to the extent that demand response resources cleared that auction. FERC's response to the FirstEnergy complaint and its response to address the D.C. Circuit Court's decision in all markets could preclude demand response resources from receiving any future capacity market revenues and also subject such resources to refund obligations. In addition, there is uncertainty as to how FERC might treat already settled capacity market auctions as well as future auctions, both for demand response resources and generation resources. FERC could grant all or a portion of the relief requested by FirstEnergy and may grant relief retroactively or only prospectively. Due to these uncertainties, the Registrants are unable to predict the outcome of these proceedings, and the final outcome is not expected for several months. Nonetheless, the final decision and its implementation by FERC and the RTOs and ISOs, could be material to Exelon, Generation, ComEd, PECO and BGE's results of operations and cash flows.

Reliability Pricing Model (Exelon, Generation and BGE). PJM's RPM Base Residual Auctions take place approximately 36 months ahead of the scheduled delivery year. The most recent auction for the delivery year ending May 31, 2018 occurred in May 2014.

New England Capacity Market Results (Exelon and Generation). Each year, ISO New England, Inc. (ISO-NE) files the results of its annual capacity auction at the FERC which is required to include documentation regarding the competitiveness of the auction. Consistent with this requirement, on February 28, 2014, ISO-NE filed the results of its eighth capacity auction (covering the June 1, 2017 through May 30, 2018 delivery period). On June 27, 2014, the FERC issued a letter to ISO-NE noting that ISO-NE's February 28, 2014 filing was deficient and that ISO-NE must file additional information before the FERC can process the filing. ISO-NE filed the information on July 17, 2014, and the ISO-NE's filings became effective by operation of law pursuant to a notice issued by the FERC's secretary on September 16, 2014. It is not clear whether any party will seek rehearing or appeal of that notice or whether any such rehearing or appeal would be effective as there is no action by the Commission to be considered. Nonetheless, while we think any change in the auction results to be unlikely, Exelon and Generation cannot predict with certainty what further action, if any, FERC or a court may take concerning the results of that auction, but any FERC or court action could be material to Exelon's and Generation's expected revenues from the capacity auction.

License Renewals (Exelon and Generation). In June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC's temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. The temporary storage rule (also referred to as the "waste confidence decision") recognizes that licensees can safely store spent nuclear fuel at nuclear plants for up to 60 years beyond the original and renewed licensed operating life of the plants and that licensing renewal decisions do not require discussion of the environmental impact of spent fuel stored on site. In August 2012, the NRC placed a hold on issuing new or renewed operating licenses that depend on the temporary storage rule until the court's decision is addressed. On August 26, 2014, the NRC Commissioners removed the hold on final licensing decisions and approved the issuance of a revised rule codifying the NRC's generic determinations regarding the environmental impacts of continued storage of spent nuclear fuel beyond a reactor's licensed operating life. The rule was issued September 19, 2014.

On October 20, 2014, the NRC approved Generation's request to extend the operating licenses of Limerick Units 1 and 2 by 20 years. The extended operating licenses for Limerick Units 1 and 2 will expire in 2044 and 2049, respectively.

On May 29, 2013, Generation submitted applications to the NRC to extend the operating licenses of Byron Units 1 and 2 and Braidwood Units 1 and 2 by 20 years. The current operating licenses for Byron Units 1 and 2 expire in 2024 and 2026, respectively. The current operating licenses for Braidwood Units 1 and 2 expire in 2026 and 2027, respectively. Generation does not expect the NRC to issue license renewals for Byron and Braidwood until 2015 at the earliest.

On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Facility Project (Muddy Run), respectively.

Generation is working with stakeholders to resolve water quality licensing issues with the MDE for Conowingo, including: (1) water quality, (2) fish passage and habitat, and (3) sediment. On January 30, 2014, Exelon filed a water quality certification application pursuant to Section 401 of the CWA with MDE for Conowingo, addressing these and other issues, although Generation cannot currently predict the conditions that ultimately may be imposed. Resolution of these issues relating to Conowingo may have a material effect on Generation's results of operations and financial position through an increase in capital expenditures and operating costs.

On June 3, 2014, PA DEP issued its water quality certificate for Muddy Run, which is a necessary step in the FERC licensing process and included certain commitments made by Generation. The financial impact associated with these commitments is estimated to be in the range of $25 million to $35 million, and will include both capital expenditures and operating expenses, primarily relating to fish passage and habitat improvement projects. On July 3, 2014, PPL Holtwood, LLC, the owner of the next upstream dam from Muddy Run, filed an appeal of PA DEP's issuance of its water quality certificate. Exelon is working with PA DEP and PPL to resolve PPL's concerns.

Based on the FERC procedural schedule, the FERC licensing process was not scheduled to be completed prior to the expiration of Muddy Run's current license on August 31, 2014, and the expiration of Conowingo's license on September 1, 2014. FERC is required to issue annual licenses for the facilities until the new licenses are issued. On September 10, 2014, FERC issued annual licenses for Conowingo and Muddy Run, effective as of the expiration of the current licenses. If FERC does not issue new licenses prior to the expiration of annual licenses, the annual licenses will renew automatically. The stations are currently being depreciated over their estimated useful lives, which includes the license renewal period. As of September 30, 2014, $38 million of direct costs associated with licensing efforts have been capitalized.

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

Regulatory Assets and Liabilities (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE 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.

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO and BGE as of September 30, 2014 and December 31, 2013. For additional information on the specific regulatory assets and liabilities, refer to Note 3 — Regulatory Matters of the Exelon 2013 Form 10-K.

September 30, 2014	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits	$ 208	$ 2,455	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	7	1,517	1	67	—	1,377	6	73
AMI programs	9	254	9	69	—	74	—	111
Under-recovered distribution service costs	243	223	243	223	—	—	—	—
Debt costs	9	50	7	48	2	2	1	8
Fair value of BGE long-term debt[a]	6	192	—	—	—	—	—	—
Fair value of BGE supply contract[b]	3	—	—	—	—	—	—	—
Severance	4	9	—	—	—	—	4	9
Asset retirement obligations	1	111	1	73	—	26	—	12
MGP remediation costs	39	220	32	186	6	33	1	1
RTO start-up costs	1	—	1	—	—	—	—	—
Under-recovered uncollectible accounts	—	70	—	70	—	—	—	—
Renewable energy	14	164	14	164	—	—	—	—
Energy and transmission programs	22	5	19	—	—	—	3[f]	5
Deferred storm costs	3	—	—	—	—	—	3	—
Electric generation-related regulatory asset	12	21	—	—	—	—	12	21
Rate stabilization deferral	75	101	—	—	—	—	75	101
Energy efficiency and demand response programs	84	151	—	—	—	—	84	151
Merger integration costs	2	7	—	—	—	—	2	7
Conservation voltage reduction	1	1	—	—	—	—	1	1
Under-recovered revenue decoupling[e]	14	—	—	—	—	—	14	—
Other	17	38	3	28	13	8	—	—
Total regulatory assets	$ 774	$ 5,589	$ 330	$ 928	$ 21	$ 1,520	$ 206	$ 500

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

September 30, 2014	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Other postretirement benefits	$ 53	$ 96	$ —	$ —	$ —	$ —	$ —	$ —
Nuclear decommissioning	—	2,850	—	2,371	—	479	—	—
Removal costs	110	1,455	86	1,257	—	—	24	198
Energy efficiency and demand response programs	28	2	28	—	—	2	—	—
DLC Program Costs	—	10	—	—	—	10	—	—
Energy efficiency Phase 2	—	32	—	—	—	32	—	—
Electric distribution tax repairs	20	100	—	—	20	100	—	—
Gas distribution tax repairs	8	32	—	—	8	32	—	—
Energy and transmission programs	73	13	26	13	44[c]	—	3[f]	—
Over-recovered gas and electric universal service fund costs	4	—	—	—	4	—	—	—
Revenue subject to refund[d]	47	—	47	—	—	—	—	—
Over-recovered revenue decoupling[e]	16	—	—	—	—	—	16	—
Other	5	3	—	2	3	—	2	1
Total regulatory liabilities	$ 364	$ 4,593	$ 187	$ 3,643	$ 79	$ 655	$ 45	$ 199

December 31, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits	$ 221	$ 2,794	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	10	1,459	2	65	—	1,317	8	77
AMI programs	5	159	5	35	—	58	—	66
AMI meter events	—	5	—	—	—	5	—	—
Under-recovered distribution service costs	178	285	178	285	—	—	—	—
Debt costs	12	56	9	53	3	3	1	8
Fair value of BGE long-term debt[a]	—	219	—	—	—	—	—	—
Fair value of BGE supply contract[b]	12	—	—	—	—	—	—	—
Severance	16	12	12	—	—	—	4	12
Asset retirement obligations	1	102	1	67	—	25	—	10
MGP remediation costs	40	212	33	178	6	33	1	1
RTO start-up costs	2	—	2	—	—	—	—	—
Under-recovered uncollectible accounts	—	48	—	48	—	—	—	—
Renewable energy	17	176	17	176	—	—	—	—
Energy and transmission programs	53	—	52	—	—	—	1[f]	—
Deferred storm costs	3	3	—	—	—	—	3	3
Electric generation-related regulatory asset	13	30	—	—	—	—	13	30
Rate stabilization deferral	71	154	—	—	—	—	71	154
Energy efficiency and demand response programs	73	148	—	—	—	—	73	148
Merger integration costs	2	9	—	—	—	—	2	9
Other	31	39	18	26	8	7	4	6
Total regulatory assets	$ 760	$ 5,910	$ 329	$ 933	$ 17	$ 1,448	$ 181	$ 524

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

December 31, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Other postretirement benefits	$ 2	$ 43	$ —	$ —	$ —	$ —	$ —	$ —
Nuclear decommissioning	—	2,740	—	2,293	—	447	—	—
Removal costs	99	1,423	78	1,219	—	—	21	204
Energy efficiency and demand response programs	53	—	45	—	8	—	—	—
DLC Program Costs	1	10	—	—	1	10	—	—
Energy efficiency phase II	—	21	—	—	—	21	—	—
Electric distribution tax repairs	20	114	—	—	20	114	—	—
Gas distribution tax repairs	8	37	—	—	8	37		
Energy and transmission programs	78	—	9	—	58[c]	—	11[f]	—
Over-recovered gas and electric universal service fund costs	8	—	—	—	8	—	—	—
Revenue subject to refund[d]	38	—	38	—	—	—	—	—
Over-recovered revenue decoupling[e]	16	—	—	—	—	—	16	—
Other	4	—	—	—	3	—	—	—
Total regulatory liabilities	$ 327	$ 4,388	$ 170	$ 3,512	$ 106	$ 629	$ 48	$ 204

(a) Represents the regulatory asset recorded at Exelon Corporate for the difference in the fair value of the long-term debt of BGE as of the merger date. The asset is amortized over the life of the underlying debt.

(b) Represents the regulatory asset recorded at Exelon Corporate representing the fair value of BGE's supply contracts as of the close of the merger date. BGE is allowed full recovery of the costs of its electric and gas supply contracts through approved, regulated rates. The asset is amortized over a period of approximately 3 years.

(c) Includes $28 million related to the DSP program, $11 million related to the over-recovered natural gas costs under the PGC and $5 million related to over-recovered electric transmission costs as of September 30, 2014. As of December 31, 2013, includes $34 million related to the DSP program, $8 million related to the over-recovered electric transmission costs and $16 million related to the over-recovered natural gas costs under the PGC.

(d) Primarily represents the regulatory liability for revenue subject to refund recorded pursuant to the ICC's order in the 2007 Rate Case. See Note 3 — Regulatory Matters of the Exelon 2013 Form 10-K. for further information.

(e) Represents the electric and gas distribution costs recoverable from customers under BGE's decoupling mechanism. As of September 30, 2014, BGE had a regulatory asset of $14 million related to under-recovered electric revenue decoupling and a regulatory liability of $16 million related to over-recovered natural gas revenue decoupling. As of December 31, 2013, BGE had a regulatory liability of $7 million related to over-recovered electric revenue decoupling and $9 million related to over-recovered natural gas revenue decoupling.

(f) Relates to $3 million associated with the transmission formula rate and $3 million of over-recovered natural gas supply costs as of September 30, 2014. As of December 31, 2013, includes $1 million of under-recovered electric supply costs and $11 million of over-recovered natural gas supply costs.

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

Purchase of Receivables Programs (Exelon, ComEd, PECO, and BGE)

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers. For retail suppliers participating in the utilities' consolidated billing, ComEd, PECO and BGE must purchase their customer accounts receivables. ComEd and BGE purchase receivables at a discount to primarily recover uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and permitted to recover uncollectible accounts expense from customers through distribution rates. Exelon, ComEd, PECO and BGE 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 and BGE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of the Registrants as of September 30, 2014 and December 31, 2013.

As of September 30, 2014	Exelon	ComEd	PECO	BGE
Purchased receivables[(a)]	$ 306	$ 152	$ 78	$ 76
Allowance for uncollectible accounts[(b)]	(36)	(21)	(8)	(7)
Purchased receivables, net	$ 270	$ 131	$ 70	$ 69

As of December 31, 2013	Exelon	ComEd	PECO	BGE
Purchased receivables[(a)]	$ 263	$ 105	$ 72	$ 86
Allowance for uncollectible accounts[(b)]	(30)	(16)	(7)	(7)
Purchased receivables, net	$ 233	$ 89	$ 65	$ 79

(a) PECO's gas POR program became effective on January 1, 2012 and includes a 1% discount on purchased receivables in order to recover the implementation costs of the program. If the costs are not fully recovered when PECO files its next gas distribution rate case, PECO will propose a mechanism to recover the remaining implementation costs as a distribution charge to low volume transportation customers or apply future discounts on purchased receivables from natural gas suppliers serving those customers.

(b) For ComEd and BGE, 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 (PORCB) tariff.

6. Investment in Constellation Energy Nuclear Group, LLC (Exelon and Generation)

As a result of the Constellation merger, Generation owns a 50.01% interest in CENG, a nuclear generation business. Generation has historically had various agreements with CENG to purchase power and to provide certain services. For further information regarding these agreements, see Note 25 — Related Party Transactions of the Exelon 2013 Form 10-K.

On April 1, 2014, Generation, CENG, and subsidiaries of CENG entered into a Nuclear Operating Services Agreement (NOSA) pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide 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 EDF, Inc.'s (EDFI) rights as a member of CENG (the Integration Transaction). CENG will reimburse Generation for its direct and allocated costs for such services. As part of the arrangement, Nine Mile Point Nuclear Station, LLC, a subsidiary of CENG, also assigned to Generation its obligations as Operator of Nine Mile Point Unit 2 under an operating agreement with the co-owner. In addition, on April 1, 2014, the Power Services Agency Agreement (PSAA) was amended and extended until the permanent cessation of power generation by the CENG generation plants.

In addition, on April 1, 2014, Generation made a $400 million loan to CENG, bearing interest at 5.25% per annum and payable out of specified available cash flows of CENG and, in any event, payable upon the settlement of the Put Option Agreement discussed below (if the put option is exercised) or payable upon the maturity date of April 1, 2034, whichever occurs first. Immediately following receipt of the proceeds of such loan, CENG made a $400 million special distribution to EDFI.

Exelon, Generation, and subsidiaries of Generation, EDFI and its parent (E.D.F. International S.A.S.), and CENG also executed a Fourth Amended and Restated Operating Agreement for CENG (Operating Agreement) on April 1, 2014, pursuant to which, among other things, CENG committed to make preferred distributions to Generation (after repayment of the $400 million loan and associated interest) quarterly out of specified available cash flows until Generation has received aggregate distributions of $400 million plus a return of 8.5% per annum from April 1, 2014 (Preferred Distribution Rights).

Generation and EDFI also entered into a Put Option Agreement on April 1, 2014, pursuant to which EDFI has the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. The appraisers determining fair market value of EDF's 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation's rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation's rights to other distributions. The beginning of the exercise period will be accelerated if Exelon's affiliates cease to own a majority of CENG and exercise a related right to terminate the NOSA. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

On April 1, 2014, Generation also executed an Indemnity Agreement pursuant to which Generation indemnified EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this indemnity.

In addition, on April 1, 2014, Generation, EDFI, CENG and Nine Mile Point Nuclear Station, LLC entered into an Employee Matters Agreement (EMA) that provides for the transfer of CENG employees to Generation or one of its affiliates (the Generation Parties) and Exelon's assumption of sponsorship of the employee benefit plans (including certain incentive, health and welfare, and postemployment benefit plans, among others) and their related trust funds as of July 14, 2014. The EMA also generally requires CENG to fund obligations related to pre-transfer service of employees, including the underfunded balance of the pension and other postretirement welfare benefit plans measured as of July 14, 2014 by making periodic payments to Generation. These payments will be made on an agreed payment schedule or upon the occurrence of certain specified events, such as EDF's disposition of a majority of its interest in CENG.

As a condition to obtaining regulatory approval for the NOSA and related transactions from the NRC, Exelon executed a support agreement pursuant to which Exelon may be required under specified circumstances to provide up to $245 million of financial support to the CENG plants (Exelon Support Agreement). The Exelon Support Agreement supersedes a previous support agreement under which Generation had agreed to provide up to $205 million of financial support for CENG. In addition, Exelon executed a guarantee pursuant to which Exelon may be required under specified circumstances to provide up to $165 million in additional financial support for CENG. A previous support agreement executed by an affiliate of EDF remains in effect under which the EDF affiliate may be required to provide up to approximately $145 million of financial support for CENG under specified circumstances. The agreements were executed as of April 1, 2014 when the NRC licenses were transferred to Generation. No liability has been recognized by Exelon for the Exelon Support Agreement or the guarantee.

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. From January 1, 2014, through March 31, 2014, Generation recorded $19 million of equity in losses of unconsolidated affiliates related to its investment in CENG and recorded $17 million of revenues from CENG. For the three and nine months ended September 30, 2013, Generation recorded $37 million and $5 million, respectively, of equity in earnings of unconsolidated affiliates related to its investment in CENG and $12 million and $45 million, respectively, of revenues from CENG. The book value of Generation's investment in CENG prior to the consolidation was $1.9 billion, and the book value of the AOCI related to CENG prior to consolidation was $116 million, net of taxes of $77 million.

As a result of the consolidation of CENG, there are several transactions included in Exelon's and Generation's Consolidated Financial Statements between CENG and EDF that are considered related party transactions to Generation. As further described in Note 25 — Related Party Transactions of the Exelon 2013 Form 10-K, EDF and Generation have a PPA with CENG under which they purchase 15% and 85%, respectively, of the nuclear output owned by CENG that is not sold to third parties under pre-existing PPAs. Beginning January 1, 2015 and continuing through the life of the respective plants, EDF and Generation will purchase 49.99% and 50.01%, respectively, of the nuclear output owned by CENG. Beginning April 1, 2014, sales to Generation are eliminated in consolidation. For the three and nine months ended September 30, 2014, Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income include sales to EDF of $52 million and $90 million, respectively. See discussion above and Note 3 — Variable Interest Entities for additional information regarding other related party transactions, between CENG and EDF included within Exelon and Generation's financial statements.

See Note 3 — Variable Interest Entities for additional information about the Registrants VIEs.

Accounting for the Consolidation of CENG

The transfer of the nuclear operating licenses and the execution of the NOSA on April 1, 2014, resulted in the derecognition of the equity method investment in CENG and the recording of all assets, liabilities and EDF's noncontrolling interest in CENG at fair value on Exelon's and Generation's Consolidated Balance Sheets. As a result of the consolidation, Exelon and Generation recorded a net gain of $261 million within their respective Consolidated Statements of Operations and Comprehensive Income. This gain consists of approximately $136 million related to the step up to fair value basis of Generation's ownership interest in CENG, and approximately $132 million related to the settlement of pre-existing transactions between CENG and Generation. The net gain on the consolidation of CENG of $261 million is net of a $7 million payment to EDF.

The fair value of CENG's assets and liabilities recorded in consolidation was 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 market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and duration of liabilities assumed.

The valuations necessary to assess the fair values of certain assets and liabilities are considered preliminary as a result of the short time period between the execution of the NOSA and the end of the second quarter of 2014. The estimates of the fair value of assets and liabilities may be modified up to one year from April 1, 2014, as more information is obtained about the fair value of assets and liabilities. The principal items that are expected to be revised include the asset retirement obligation liabilities and related asset retirement costs. These items are expected to be updated with inputs from a third party engineering firm with corresponding adjustments recorded by the end of 2014. See Note 12 — Nuclear Decommissioning for discussion of the impacts of adjustments recorded during the third quarter of 2014 related to updated estimates of the CENG asset retirement obligation liabilities. In the period of such revisions, these and any other material changes to the fair value assessments could result in adjustments to the amounts recorded upon consolidation, including the overall gain recorded by Generation. In addition, any asset or liability adjustments impacting depreciation and/or accretion expense recorded after the consolidation date would impact Generation's post-consolidation results of operations.

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

Generation recorded the assets and liabilities of CENG at fair value as of April 1, 2014. The following assets and liabilities of CENG were recorded within Generation's Consolidated Balance Sheets as of the date of integration:

Preliminary Fair Values	Exelon and Generation
Current assets	$ 499
Nuclear decommissioning trust fund	1,955
Property, plant and equipment	2,941
Nuclear fuel	482
Other assets	10
Total assets	5,887
Current liabilities	237
Asset retirement obligation	1,684
Pension and other employee benefit obligations	281
Unamortized energy contract liabilities	171
Other liabilities	114
Total liabilities	2,487
Total net assets	$ 3,400

Generation also recorded the fair value of the noncontrolling interest on its Consolidated Balance Sheets of approximately $1.5 billion, net of the fair value of $152 million for certain specified additional distribution rights under the Operating Agreement. In addition, the noncontrolling interest was further reduced by the $400 million special cash distribution to EDF.

Due to the Preferred Distribution Rights that Generation has on CENG's available cash, the earnings attributable to the noncontrolling interest on the Statements of Operations and Comprehensive Income as well as the corresponding adjustment to Non-controlling interest on the Consolidated Balance Sheets will not be in proportion to Generation's and EDF's equity ownership interests. Rather, the attribution will consider Generation's Preferred Distribution Rights and allocate net income based on each owner's rights to CENG's net assets. For the three and nine months ended September 30, 2014, Generation reduced by $4 million and $8 million, respectively, the amount of Net income attributable to noncontrolling interests on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. As a result of the consolidation, Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income includes CENG's incremental operating revenues of $58 million and $155 million and CENG's net income, prior to any intercompany eliminations and any adjustments for noncontrolling interest, of $171 million and $248 million during the three and nine months ended September 30, 2014, respectively.

Exelon and Generation both incurred integration-related costs of $4 million and $22 million during the three and nine months ended September 30, 2014. The costs incurred are classified primarily within Operating and Maintenance Expense in Exelon's and Generation's respective Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2014.

See Note 14 — Severance for integration-related severance costs related to CENG incurred by Exelon and Generation during the three and nine months ended September 30, 2014.

7. 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. In the second quarter of 2014, updates to the long-term fundamental energy prices, which included a thorough evaluation of key assumptions including gas prices, load growth, plant retirements and renewable growth, suggested that the carrying value of certain merchant wind assets may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of twelve wind projects, primarily located in West Texas, were less than their respective carrying values at May 31, 2014. As a result, long-lived assets held and used with a carrying amount of approximately $151 million were written down to their fair value of $65 million and a pre-tax impairment charge of $86 million was recorded during the second quarter of 2014 in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

In the third quarter of 2013, lower projected wind production and a decline in power prices suggested that the carrying value of certain wind projects may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of eleven wind projects, primarily located in West Texas and Minnesota, were less than their respective carrying values at September 30, 2013. As a result, long-lived assets held and used with a carrying amount of approximately $75 million were written down to their fair value of $32 million and a pre-tax impairment charge of $39 million, net of the impairment amount attributable to noncontrolling interests for certain of the projects, was recorded during the third quarter of 2013 in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

The fair value analysis in both quarters was primarily based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. Changes in the assumptions described above could potentially result in future impairments of Exelon's long-lived assets, which could be material.

During the third quarter of 2014, certain non-nuclear generating assets were identified as assets held for sale on Exelon's and Generation's Consolidated Balance Sheets. When long-lived assets are held for sale, an impairment loss is recognized to the extent that the asset's carrying value exceeds its estimated fair value less costs to sell. At September 30, 2014, in connection with the approved asset sales agreements, a $50 million pre-tax impairment loss was recorded within Operating and maintenance expense on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. See Note 4 — Mergers, Acquisitions, and Dispositions for further information on assets held for sale.

Nuclear Uprate Program (Exelon and Generation)

Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan was adjusted in both the first and second quarters of 2013 to cancel certain projects. During the first quarter of 2013, the Measurement Uncertainty Recapture (MUR) uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. For these cancelled projects, Generation recorded approximately $21 million to Operating and maintenance expense during the first quarter of 2013 to accrue remaining costs and reverse previously capitalized costs. During the second quarter of 2013, market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. For these cancelled projects, Generation recorded a pre-tax charge during the second quarter of 2013 to Operating and maintenance expense and Interest expense of approximately $92 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Like-Kind Exchange Transaction (Exelon)

Prior to the PECO/Unicom Merger in October 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon, entered into a like-kind exchange transaction pursuant to which approximately $1.6 billion was invested in coal-fired generating station leases located in Georgia and Texas with two separate entities unrelated to Exelon. The generating stations were leased back to such entities as part of the transaction. See Note 11 — Income Taxes for further information. For financial accounting purposes, the investments are accounted for as direct financing lease investments. UII holds the leasehold interests in the generating stations in several separate bankruptcy remote, special purpose companies it directly or indirectly wholly owns. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to operate the stations and keep or market the power itself or require the lessees to arrange for a third-party to bid on a service contract for a period following the lease term. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. In the fourth quarter of 2000, under the terms of the lease agreements, UII received a prepayment of $1.2 billion for all rent, which reduced the investment in the leases. There are no minimum scheduled lease payments to be received over the remaining term of the leases.

On February 26, 2014, UII and the City Public Service Board of San Antonio, Texas (CPS) finalized an agreement to terminate the lease on the generating station located in Texas prior to its expiration date. As a result of the lease termination, UII received a net early termination amount of $335 million from CPS and wrote off the net investment in the CPS long-term lease of $336 million in Investments in the Consolidated Balance Sheet in the first quarter of 2014 resulting in a pre-tax loss of $1 million being reflected in Operating and maintenance expense in the Consolidated Statement of Operations and Comprehensive Income in the first quarter of 2014.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and record an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments under the income approach, which uses a discounted cash flow analysis, which takes into consideration significant unobservable inputs (Level 3) including the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. Significant assumptions used in estimating the fair value include fundamental energy and capacity prices, fixed and variable costs, capital expenditure requirements, discount rates, tax rates, and the estimated remaining useful lives of the plants. The estimated fair values also reflect the cash flows associated with the service contract option discussed above given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

Based on the annual reviews performed in the second quarter of 2014 and 2013, the estimated residual value of Exelon's direct financing leases for the Georgia generating stations experienced other than temporary declines given reduced long-term energy and capacity price expectations. As a result, Exelon recorded a $24 million and $14 million pre-tax impairment charge in the second quarter of 2014 and 2013, respectively, for these stations. These impairment charges were recorded in Investments and Operating and maintenance expense in Exelon's Consolidated Balance Sheet and the Consolidated Statement of Operations and Comprehensive Income, respectively. Changes in the assumptions described above could potentially result in future impairments of Exelon's direct financing lease investments, which could be material.

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

At September 30, 2014 and December 31, 2013, the components of the net investment in long-term leases were as follows:

	September 30, 2014	December 31, 2013
Estimated residual value of leased assets	$ 685	$ 1,465
Less: unearned income	328	767
Net investment in long-term leases	$ 357	$ 698

8. Fair Value of Financial Assets and Liabilities (Exelon, Generation, ComEd, PECO and BGE)

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 September 30, 2014 and December 31, 2013:

Exelon

	September 30, 2014				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 565	$ 3	$ 562	$ —	$ 565
Long-term debt (including amounts due within one year)	21,264	1,168	20,278	1,297	22,743
Long-term debt to financing trusts	648	—	—	677	677
SNF obligation	1,021	—	849	—	849

	December 31, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 344	$ 3	$ 341	$ —	$ 344
Long-term debt (including amounts due within one year)	19,132	—	18,672	1,079	19,751
Long-term debt to financing trusts	648	—	—	631	631
SNF obligation	1,021	—	790	—	790

Generation

	September 30, 2014				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 14	$ —	$ 14	$ —	$ 14
Long-term debt (including amounts due within one year)	8,320	—	7,543	1,297	8,840
SNF obligation	1,021	—	849	—	849

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

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	December 31, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 22	$ —	$ 22	$ —	$ 22
Long-term debt (including amounts due within one year)	7,729	—	6,586	1,062	7,648
SNF obligation	1,021	—	790	—	790

ComEd

	September 30, 2014				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 528	$ —	$ 528	$ —	$ 528
Long-term debt (including amounts due within one year)	5,708	—	6,422	—	6,422
Long-term debt to financing trust	206	—	—	214	214

	December 31, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 184	$ —	$ 184	$ —	$ 184
Long-term debt (including amounts due within one year)	5,675	—	6,238	17	6,255
Long-term debt to financing trust	206	—	—	202	202

PECO

	September 30, 2014				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 2,496	$ —	$2,720	$ —	$2,720
Long-term debt to financing trusts	184	—	—	204	204

	December 31, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 2,197	$ —	$2,358	$ —	$2,358
Long-term debt to financing trusts	184	—	—	180	180

BGE

	September 30, 2014				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 23	$ 3	$ 20	$ —	$ 23
Long-term debt (including amounts due within one year)	1,976	—	2,196	—	2,196
Long-term debt to financing trusts	258	—	—	259	259

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

	December 31, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 138	$ 3	$ 135	$ —	$ 138
Long-term debt (including amounts due within one year)	2,011	—	2,148	—	2,148
Long-term debt to financing trusts	258	—	—	249	249

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of short-term borrowings (Level 2) and dividends payable (included in other current liabilities) (Level 1). 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) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the electric utility sector with similar credit ratings in both the primary and secondary market, across the Registrants' debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note. 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 non-government-backed fixed rate project financing debt (Level 3) is based on market and quoted prices for its own and other project financing debt with similar risk profiles. Given the low trading volume in the project financing debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project (e.g., political and regulatory environment). The fair value of Generation's government-backed fixed rate project financing debt (Level 3) is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate project financing debt resets on a quarterly basis and the carrying value approximates fair value (Level 2).

SNF Obligation. The carrying amount of Generation's SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation estimated to be settled in 2025 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2025.

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 access as of the reporting date. Financial assets and liabilities utilizing Level 1 inputs include active exchange-traded corporate units, equity securities and funds, certain exchange-based derivatives, and money market funds.
- 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. Financial assets and liabilities utilizing Level 2 inputs include fixed income securities, derivatives, commingled and mutual investment funds priced at NAV per fund share and fair value hedges.
- 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. Financial assets and liabilities utilizing Level 3 inputs include infrequently traded securities and derivatives, and investments priced using an alternative pricing mechanism or third party valuation.

Transfers in and out of levels are recognized as of the end of the reporting period 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. Transfers into Level 2 from Level 3 generally occur when the contract tenure becomes more observable. Transfers into Level 3 from Level 2 generally occur due to changes in market liquidity or assumptions for certain commodity contracts. There were no transfers between Level 1 and Level 2 during the nine months ended September 30, 2014 for cash equivalents, nuclear decommissioning trust fund investments, pledged assets for Zion Station decommissioning, Rabbi trust investments, and deferred compensation obligations.

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

Exelon and Generation

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 September 30, 2014 and December 31, 2013:

	Generation				Exelon			
As of September 30, 2014	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets								
Cash equivalents[a]	$ 944	$ —	$ —	$ 944	$ 1,876	$ —	$ —	$ 1,876
Nuclear decommissioning trust fund investments								
Cash equivalents	261	62	—	323	261	62	—	323
Equity								
Individually held	2,569	—	—	2,569	2,569	—	—	2,569
Exchange traded funds	170	—	—	170	170	—	—	170
Commingled funds	—	2,365	—	2,365	—	2,365	—	2,365
Equity funds subtotal	2,739	2,365	—	5,104	2,739	2,365	—	5,104
Balanced funds — commingled funds	—	273	—	273	—	273	—	273
Fixed income								
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	967	—	—	967	967	—	—	967
Debt securities issued by states of the United States and political subdivisions of the states	—	429	—	429	—	429	—	429
Debt securities issued by foreign governments	—	105	—	105	—	105	—	105
Corporate debt securities	—	2,001	235	2,236	—	2,001	235	2,236
Federal agency mortgage-backed securities	—	79	—	79	—	79	—	79
Commercial mortgage-backed securities (non-agency)	—	39	—	39	—	39	—	39
Residential mortgage-backed securities (non-agency)	—	3	—	3	—	3	—	3
Mutual funds	—	21	—	21	—	21	—	21
Commingled funds	—	328	—	328	—	328	—	328
Fixed income subtotal	967	3,005	235	4,207	967	3,005	235	4,207
Middle market lending	—	—	354	354	—	—	354	354
Private Equity	—	—	54	54	—	—	54	54
Other debt obligations	—	19	—	19	—	19	—	19
Real Estate	—	—	1	1	—	—	1	1
Nuclear decommissioning trust fund investments subtotal[b]	3,967	5,724	644	10,335	3,967	5,724	644	10,335
Pledged assets for Zion Station decommissioning								
Cash equivalents	—	12	—	12	—	12	—	12
Equity								
Individually held	5	2	—	7	5	2	—	7
Equity funds subtotal	5	2	—	7	5	2	—	7
Fixed income								
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	13	2	—	15	13	2	—	15
Debt securities issued by states of the United States and political subdivisions of the states	—	19	—	19	—	19	—	19
Corporate debt securities	—	138	—	138	—	138	—	138
Commingled funds	—	4	—	4	—	4	—	4
Fixed income subtotal	13	163	—	176	13	163	—	176
Middle market lending	—	—	166	166	—	—	166	166
Pledged assets for Zion Station decommissioning subtotal[c]	18	177	166	361	18	177	166	361
Rabbi trust investments[e]								
Mutual funds[d]	15	—	—	15	46	—	—	46
Rabbi trust investments subtotal	15	—	—	15	46	—	—	46
Commodity derivative assets								
Economic hedges	396	2,523	1,683	4,602	396	2,523	1,683	4,602
Proprietary trading	129	537	214	880	129	537	214	880
Effect of netting and allocation of collateral[f]	(563)	(2,472)	(1,213)	(4,248)	(563)	(2,472)	(1,213)	(4,248)
Commodity derivative assets subtotal	(38)	588	684	1,234	(38)	588	684	1,234

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

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As of September 30, 2014	Generation Level 1	Generation Level 2	Generation Level 3	Generation Total	Exelon Level 1	Exelon Level 2	Exelon Level 3	Exelon Total
Interest rate and foreign currency derivative assets								
Derivatives designated as hedging instruments	—	13	—	13	—	25	—	25
Economic hedges	—	7	—	7	—	12	—	12
Proprietary trading	18	3	—	21	18	3	—	21
Effect of netting and allocation of collateral	(19)	(5)	—	(24)	(19)	(5)	—	(24)
Interest rate and foreign currency derivative assets subtotal	(1)	18	—	17	(1)	35	—	34
Other investments	13	—	3	16	13	—	3	16
Total assets	4,918	6,507	1,497	12,922	5,881	6,524	1,497	13,902
Liabilities								
Commodity derivative liabilities								
Economic hedges	(458)	(2,194)	(1,494)	(4,146)	(458)	(2,194)	(1,672)	(4,324)
Proprietary trading	(133)	(555)	(203)	(891)	(133)	(555)	(203)	(891)
Effect of netting and allocation of collateral[f]	591	2,672	1,444	4,707	591	2,672	1,444	4,707
Commodity derivative liabilities subtotal	—	(77)	(253)	(330)	—	(77)	(431)	(508)
Interest rate and foreign currency derivative liabilities								
Derivatives designated as hedging instruments	—	(2)	—	(2)	—	(12)	—	(12)
Economic hedges	—	(9)	—	(9)	—	(22)	—	(22)
Proprietary trading	(17)	(3)	—	(20)	(17)	(3)	—	(20)
Effect of netting and allocation of collateral	17	5	—	22	17	5	—	22
Interest rate and foreign currency derivative liabilities subtotal	—	(9)	—	(9)	—	(32)	—	(32)
Deferred compensation obligation	—	(29)	—	(29)	—	(105)	—	(105)
Total liabilities	—	(115)	(253)	(368)	—	(214)	(431)	(645)
Total net assets	$ 4,918	$ 6,392	$ 1,244	$12,554	$ 5,881	$ 6,310	$ 1,066	$13,257

As of December 31, 2013	Generation Level 1	Generation Level 2	Generation Level 3	Generation Total	Exelon Level 1	Exelon Level 2	Exelon Level 3	Exelon Total
Assets								
Cash equivalents[a]	$ 1,006	$ —	$ —	$1,006	$ 1,230	$ —	$ —	$1,230
Nuclear decommissioning trust fund investments								
Cash equivalents	459	—	—	459	459	—	—	459
Equity								
Individually held	1,776	—	—	1,776	1,776	—	—	1,776
Exchange traded funds	115	—	—	115	115	—	—	115
Commingled funds	—	2,271	—	2,271	—	2,271	—	2,271
Equity funds subtotal	1,891	2,271	—	4,162	1,891	2,271	—	4,162
Fixed income								
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	882	—	—	882	882	—	—	882
Debt securities issued by states of the United States and political subdivisions of the states	—	294	—	294	—	294	—	294
Debt securities issued by foreign governments	—	87	—	87	—	87	—	87
Corporate debt securities	—	1,753	31	1,784	—	1,753	31	1,784
Federal agency mortgage-backed securities	—	10	—	10	—	10	—	10
Commercial mortgage-backed securities (non-agency)	—	40	—	40	—	40	—	40
Residential mortgage-backed securities (non-agency)	—	7	—	7	—	7	—	7
Mutual funds	—	18	—	18	—	18	—	18
Fixed income subtotal	882	2,209	31	3,122	882	2,209	31	3,122
Middle market lending	—	—	314	314	—	—	314	314
Private Equity	—	—	5	5	—	—	5	5
Other debt obligations	—	14	—	14	—	14	—	14
Nuclear decommissioning trust fund investments subtotal[b]	3,232	4,494	350	8,076	3,232	4,494	350	8,076
Pledged assets for Zion Station decommissioning								
Cash equivalents	—	26	—	26	—	26	—	26
Equity								
Individually held	16	—	—	16	16	—	—	16
Equity funds subtotal	16	—	—	16	16	—	—	16

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

	Generation				Exelon			
As of December 31, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Fixed income								
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	45	4	—	49	45	4	—	49
Debt securities issued by states of the United States and political subdivisions of the states	—	20	—	20	—	20	—	20
Corporate debt securities	—	227	—	227	—	227	—	227
Fixed income subtotal	45	251	—	296	45	251	—	296
Middle market lending	—	—	112	112	—	—	112	112
Other debt obligations	—	1	—	1	—	1	—	1
Pledged assets for Zion Station decommissioning subtotal(c)	61	278	112	451	61	278	112	451
Rabbi trust investments(e)								
Cash equivalents	—	—	—	—	2	—	—	2
Mutual funds(d)	13	—	—	13	54	—	—	54
Rabbi trust investments subtotal	13	—	—	13	56	—	—	56
Commodity derivative assets								
Economic hedges	493	2,582	885	3,960	493	2,582	885	3,960
Proprietary trading	324	1,315	122	1,761	324	1,315	122	1,761
Effect of netting and allocation of collateral(f)	(863)	(3,131)	(430)	(4,424)	(863)	(3,131)	(430)	(4,424)
Commodity derivative assets subtotal	(46)	766	577	1,297	(46)	766	577	1,297
Interest rate and foreign currency derivative assets	30	32	—	62	30	39	—	69
Effect of netting and allocation of collateral	(30)	(2)	—	(32)	(30)	(2)	—	(32)
Interest rate and foreign currency derivative assets subtotal	—	30	—	30	—	37	—	37
Other investments	—	—	15	15	—	—	15	15
Total assets	4,266	5,568	1,054	10,888	4,533	5,575	1,054	11,162
Liabilities								
Commodity derivative liabilities								
Economic hedges	(540)	(1,890)	(397)	(2,827)	(540)	(1,890)	(590)	(3,020)
Proprietary trading	(328)	(1,256)	(119)	(1,703)	(328)	(1,256)	(119)	(1,703)
Effect of netting and allocation of collateral(f)	869	3,007	404	4,280	869	3,007	404	4,280
Commodity derivative liabilities subtotal	1	(139)	(112)	(250)	1	(139)	(305)	(443)
Interest rate and foreign currency derivative liabilities	(31)	(13)	—	(44)	(31)	(17)	—	(48)
Effect of netting and allocation of collateral	31	1	—	32	31	1	—	32
Interest rate and foreign currency derivative liabilities subtotal	—	(12)	—	(12)	—	(16)	—	(16)
Deferred compensation obligation	—	(29)	—	(29)	—	(114)	—	(114)
Total liabilities	1	(180)	(112)	(291)	1	(269)	(305)	(573)
Total net assets	$ 4,267	$ 5,388	$ 942	$10,597	$ 4,534	$ 5,306	$ 749	$10,589

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net assets (liabilities) of $14 million and $(5) million at September 30, 2014 and December 31, 2013, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(c) Excludes net assets of $4 million and $7 million at September 30, 2014 and December 31, 2013, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) The mutual funds held by the Rabbi trusts at Exelon include $45 million related to deferred compensation and $1 million related to Supplemental Executive Retirement Plan at September 30, 2014, and $53 million related to deferred compensation and $1 million related to Supplemental Executive Retirement Plan at December 31, 2013.
(e) Excludes $11 million and $35 million of cash surrender value of life insurance investment at September 30, 2014 and $10 million and $32 million of cash surrender value of life insurance investment at December 31, 2013 at Generation and Exelon, respectively.
(f) Includes collateral postings (received) from counterparties. Collateral posted (received) from counterparties for commodity positions, net of collateral paid to counterparties, totaled $28 million, $200 million and $231 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of September 30, 2014. Collateral posted (received) from counterparties, net of collateral paid to counterparties, totaled $6 million, $(124) million and $(26) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2013.

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

ComEd, PECO and BGE

The following tables present assets and liabilities measured and recorded at fair value on the ComEd, PECO and BGE Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of September 30, 2014 and December 31, 2013:

	ComEd				PECO				BGE			
As of September 30, 2014	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents	$ —	$ —	$ —	$ —	$ 304	$ —	$ —	$304	$ 5	$ —	$ —	$ 5
Rabbi trust investments												
Mutual funds[(a)]	—	—	—	—	9	—	—	9	5	—	—	5
Rabbi trust investments subtotal	—	—	—	—	9	—	—	9	5	—	—	5
Total assets	—	—	—	—	313	—	—	313	10	—	—	10
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(15)	—	(15)	—	(5)	—	(5)
Mark-to-market derivative liabilities[(b)]	—	—	(178)	(178)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(178)	(186)	—	(15)	—	(15)	—	(5)	—	(5)
Total net assets (liabilities)	$ —	$ (8)	$(178)	$(186)	$ 313	$ (15)	$ —	$298	$ 10	$ (5)	$ —	$ 5

	ComEd				PECO				BGE			
As of December 31, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents	$ —	$ —	$ —	$ —	$ 175	$ —	$ —	$175	$ 31	$ —	$ —	$ 31
Rabbi trust investments												
Mutual funds[(a)]	5	—	—	5	9	—	—	9	6	—	—	6
Rabbi trust investments subtotal	5	—	—	5	9	—	—	9	6	—	—	6
Total assets	5	—	—	5	184	—	—	184	37	—	—	37
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(17)	—	(17)	—	(6)	—	(6)
Mark-to-market derivative liabilities[(b)]	—	—	(193)	(193)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(193)	(201)	—	(17)	—	(17)	—	(6)	—	(6)
Total net assets (liabilities)	$ 5	$ (8)	$(193)	$(196)	$ 184	$ (17)	$ —	$167	$ 37	$ (6)	$ —	$ 31

(a) At PECO, excludes $14 million of the cash surrender value of life insurance investments at both September 30, 2014 and December 31, 2013.
(b) The Level 3 balance includes the current and noncurrent liability of $14 million and $164 million at September 30, 2014, respectively, and $17 million and $176 million at December 31, 2013, respectively, 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)

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2014 and 2013:

	Generation					ComEd	Exelon
Three Months Ended September 30, 2014	**Nuclear Decommissioning Trust Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total Generation**	**Mark-to-Market Derivatives[b]**	**Total**
Balance as of June 30, 2014	$ 592	$ 133	$ 242	$ 10	$ 977	$ (134)	$ 843
Total realized / unrealized gains (losses)							
Included in net income	1	—	76[a]	—	77	—	77
Included in noncurrent payables to affiliates	3	—	—	—	3	—	3
Included in payable for Zion Station decommissioning	—	(2)	—	—	(2)	—	(2)
Included in regulatory assets	—	—	—	—	—	(44)	(44)
Change in collateral	—	—	79	—	79	—	79
Purchases, sales, issuances and settlements							
Purchases	83	53	12	—	148	—	148
Sales	(8)	(18)	—	(7)	(33)	—	(33)
Settlements	(27)	—	—	—	(27)	—	(27)
Transfers into Level 3	—	—	21	—	21	—	21
Transfers out of Level 3	—	—	1	—	1	—	1
Balance as of September 30, 2014	$ 644	$ 166	$ 431	$ 3	$ 1,244	$ (178)	$ 1,066
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the three months ended September 30, 2014	$ 1	$ —	$ 163	$ —	$ 164	$ —	$ 164

	Generation					ComEd	Exelon
Nine Months Ended September 30, 2014	**Nuclear Decommissioning Trust Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total Generation**	**Mark-to-Market Derivatives[b]**	**Total**
Balance as of December 31, 2013	$ 350	$ 112	$ 465	$ 15	$ 942	$ (193)	$ 749
Total realized / unrealized gains (losses)							
Included in net income	5	—	(284)[a]	—	(279)	—	(279)
Included in noncurrent payables to affiliates	14	—	—	—	14	—	14
Included in payable for Zion Station decommissioning	—	2	—	—	2	—	2
Included in regulatory assets	—	—	—	—	—	15	15
Change in collateral	—	—	257	—	257	—	257
Purchases, sales, issuances and settlements							
Purchases	331	95	27	2	455	—	455
Sales	(10)	(43)	(6)	(7)	(66)	—	(66)
Settlements	(46)	—	—	—	(46)	—	(46)
Transfers into Level 3	—	—	(9)	—	(9)	—	(9)
Transfers out of Level 3	—	—	(19)	(7)	(26)	—	(26)
Balance as of September 30, 2014	$ 644	$ 166	$ 431	$ 3	$ 1,244	$ (178)	$ 1,066
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the nine months ended September 30, 2014	$ 3	$ —	$ (264)	$ —	$ (261)	$ —	$ (261)

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

(a) Includes an increase for the reclassification of $87 million and $20 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and nine months ended September 30, 2014, respectively.
(b) Includes $45 million of increases and $19 million of decreases in fair value and realized losses due to settlements of $1 million and realized gains due to settlements of $4 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three and nine months ended September 30, 2014, respectively.

	Generation					ComEd	Exelon
Three Months Ended September 30, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives[c]	Total
Balance as of June 30, 2013	$ 240	$ 111	$ 516	$ 11	$ 878	$ (85)	$ 793
Total realized / unrealized gains (losses)							
Included in net income	—	—	(32)[a]	—	(32)	—	(32)
Included in noncurrent payables to affiliates	(1)	—	—	—	(1)	—	(1)
Included in payable for Zion Station decommissioning	—	—	—	—	—	—	—
Included in regulatory assets	—	—	—	—	—	(37)	(37)
Change in collateral	—	—	(30)	—	(30)	—	(30)
Purchases, sales, issuances and settlements							
Purchases	23	10	8	—	41	—	41
Sales	(14)	(15)	—	—	(29)	—	(29)
Settlements	(3)	—	—	—	(3)	—	(3)
Transfers into Level 3	—	—	4	—	4	—	4
Transfers out of Level 3	—	—	(5)	—	(5)	—	(5)
Balance as of September 30, 2013	$ 245	$ 106	$ 461	$ 11	$ 823	$ (122)	$ 701
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the three months ended September 30, 2013	$ —	$ —	$ 51	$ —	$ 51	$ —	$ 51

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

Nine Months Ended September 30, 2013	Generation: Nuclear Decommissioning Trust 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[c][d]	Exelon: Total
Balance as of December 31, 2012	$ 183	$ 89	$ 660	$ 17	$ 949	$ (293)	$ 656
Total realized / unrealized gains (losses)							
Included in net income	2	—	(8)[a][b]	—	(6)	—	(6)
Included in other comprehensive income	—	—	(219)[b]	—	(219)	—	(219)
Included in noncurrent payables to affiliates	8	—	—	—	8	226	234
Included in payable for Zion Station decommissioning	—	1	—	—	1	—	1
Included in regulatory assets	—	—	—	—	—	(55)	(55)
Change in collateral	—	—	13	—	13	—	13
Purchases, sales, issuances and settlements							
Purchases	90	43	16	2	151	—	151
Sales	(27)	(27)	(8)	(8)	(70)	—	(70)
Settlements	(11)	—	—	—	(11)	—	(11)
Transfers into Level 3	—	—	11	—	11	—	11
Transfers out of Level 3	—	—	(4)	—	(4)	—	(4)
Balance as of September 30, 2013	$ 245	$ 106	$ 461	$ 11	$ 823	$ (122)	$ 701
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the nine months ended September 30, 2013	$ 1	$ —	$ 148	$ —	$ 149	$ 11	$ 160

(a) Includes the reclassification of $83 million and $156 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and nine months ended September 30, 2013, respectively.

(b) Includes $11 million of increases in fair value and realized gains due to settlements of $215 million associated with Generation's financial swap contract with ComEd for the nine months ended September 30, 2013. This position eliminates upon consolidation in Exelon's Consolidated Financial Statements.

(c) Includes $11 million of decreases in fair value and realized gains due to settlements of $215 million associated with Generation's financial swap contract with ComEd for the nine months ended September 30, 2013. This position eliminates upon consolidation in Exelon's Consolidated Financial Statements.

(d) Includes $37 million and $57 million of increases in fair value and realized losses due to settlements of $1 million and $5 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three and nine months ended September 30, 2013, respectively.

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

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2014 and 2013:

	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 September 30, 2014	$ 70	$ 6	$ 1	$ 70	$ 6	$ 1
Total gains (losses) included in net income for the nine months ended September 30, 2014	(260)	(24)	5	(260)	(24)	5
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2014	142	21	1	142	21	1
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2014	(293)	29	3	(293)	29	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 September 30, 2013	$ (39)	$ 7	$ —	$ (39)	$ 7	$ —
Total gains (losses) included in net income for the nine months ended September 30, 2013	(67)	59	2	(61)	60	2
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2013	42	9	—	42	9	—
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2013	71	77	1	81	78	1

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

Valuation Techniques Used to Determine Fair Value

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

Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE). 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.

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. Generation's and CENG's investment policies place limitations on the types and investment grade ratings of the securities that may be held by the trusts. These policies 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 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 are based on quoted prices in active markets and are categorized in Level 1. 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. 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 are determined using a third party valuation that contains significant unobservable inputs and are categorized in Level 3.

Equity, balanced and fixed income commingled funds and fixed income mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair values of fixed income commingled and mutual funds held within the trust funds, which generally hold short-term fixed income securities and are not subject to restrictions regarding the purchase or sale of shares, are derived from observable prices. The objectives of the remaining equity commingled funds in which Exelon, Generation, and CENG invest primarily seek to track the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. Commingled and mutual funds are categorized in Level 2 because the fair value of the funds are based on NAVs per fund share (the unit of account), primarily derived from the quoted prices in active markets on the underlying equity securities. See Note 12 — Nuclear Decommissioning for further discussion on the NDT fund investments.

Middle market lending are investments in loans or managed funds which invest in 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 middle market lending 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. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

As of September 30, 2014, Generation has outstanding commitments to invest in middle market lending, corporate debt securities, private equity investments, and real estate investments of approximately $344 million. 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)

Rabbi Trust Investments (Exelon, Generation, ComEd, PECO and BGE). 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 investments in the Rabbi trusts are included in investments in the Registrants' Consolidated Balance Sheets and consist primarily of mutual funds. These 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. Mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices.

Mark-to-Market Derivatives (Exelon, Generation, and ComEd). 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 and BGE). 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 notional investments are comprised primarily of mutual funds, which are based on observable market prices. However, since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd)

Mark-to-Market Derivatives (Exelon, Generation, 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 risk officer and includes the chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the Exelon Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at Exelon. 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, coal purchases, certain transmission congestion contracts, and project financing debt. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price varies generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $3.57 and $0.45 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3. See ITEM 3. — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for information regarding the maturity by year of the Registrant's mark-to-market derivative assets and liabilities.

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

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

Type of trade	Fair Value at September 30, 2014	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives — Economic Hedges (Generation)[a][c]	$ 189	Discounted Cash Flow	Forward power price	$13 - $194[d]
			Forward gas price	$2.54 - $22.15[d]
		Option Model	Volatility percentage	8% - 154%
Mark-to-market derivatives — Proprietary trading (Generation)[a][c]	$ 11	Discounted Cash Flow	Forward power price	$14 - $191[d]
		Option Model	Volatility percentage	8% - 154%
Mark-to-market derivatives (ComEd)	$ (178)	Discounted Cash Flow	Forward heat rate[b]	8x - 9x
			Marketability reserve	3.5% - 8%
			Renewable factor	86% - 126%

(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 held on level three positions of $231 million as of September 30, 2014.
(d) The upper ends of the ranges are driven by the winter power and gas prices in the New England region. Without the New England region, the upper ends of the ranges for power and gas economic hedges would be approximately $146 and $10.62, respectively, and would be approximately $104 for power proprietary trading.

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

Type of trade	Fair Value at December 31, 2013	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives — Economic Hedges (Generation)[a][c]	$ 488	Discounted Cash Flow	Forward power price	$8 - $176[d]
			Forward gas price	$2.98 - $16.63[d]
		Option Model	Volatility percentage	15% - 142%
Mark-to-market derivatives — Proprietary trading (Generation)[a][c]	$ 3	Discounted Cash Flow	Forward power price	$10 - $176[d]
		Option Model	Volatility percentage	14% - 19%
Mark-to-market derivatives (ComEd)	$ (193)	Discounted Cash Flow	Forward heat rate[b]	8x - 9x
			Marketability reserve	3.5% - 8%
			Renewable factor	84% - 128%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
(c) The fair values do not include cash collateral held on level three positions of $26 million as of December 31, 2013
(d) The upper ends of the ranges are driven by the winter power and gas prices in the New England region. Without the New England region, the upper ends of the ranges for power and gas would be approximately $100 and $5.70, respectively.

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, certain corporate debt securities, and private equity investments, the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on valuations of comparable companies, discounting the forecasted cash flows of the portfolio company, estimating the liquidation or collateral value of the portfolio company or its assets, considering offers from third parties to buy the portfolio company, its historical and projected financial results, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied to the prices of comparable companies for factors such as size, marketability, credit risk and relative performance.

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

9. Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

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

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, the Registrants are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. The Registrants employ established policies and procedures to manage their risks associated with market fluctuations 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 commodity transactions, effective with the date of merger with Constellation, Generation no longer utilizes the special election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation's designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all derivative economic hedges for 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. Non-derivative contracts for access to additional generation and certain sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 22 — Commitments and Contingencies of the Exelon 2013 Form 10-K. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall energy marketing activities.

Economic Hedging. The Registrants are exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels, and other commodities associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. Within Exelon, Generation has the most exposure to commodity price risk. As such, Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power and gas sales, fuel and energy purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and gas and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management's policies and hedging objectives, the market, weather conditions, operational and other factors. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions that have not been hedged. Exelon's hedging program involves the hedging of commodity risk for Exelon's expected generation, typically on a ratable basis over a three-year period. This strategy has not changed as a result of recent and pending asset divestitures. As of September 30, 2014, the proportion of expected generation hedged is 98%-101%, 86%-89%, and 55%-58% for 2014, 2015, and 2016, 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 financial exposure through owned or contracted capacity and reflects the divestiture impact of Fore River, Quail Run, and West Valley; but does not reflect the divestiture impact of Generation's interest in Keystone and Conemaugh. See Note 4 – Mergers, Acquisitions and Dispositions and Note 21 – Subsequent Event for more detail regarding the divestitures. 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. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts for energy and associated RECs were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC's December 18, 2013 Order approved the reduction of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved in March 2014. 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 2013 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 and block contracts. PECO has certain full requirements contracts and block contracts that are considered derivatives and qualify for the NPNS scope exception under current derivative authoritative guidance.

PECO's natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply reliability at the least cost. PECO's reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO's natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2014 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 2014 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 30% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

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

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

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 3,006 GWhs and 8,129 GWhs for the three and nine months ended September 30, 2014, respectively, and 2,499 GWhs and 6,066 GWhs for the three and nine months ended September 30, 2013, 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 and BGE do not enter into derivatives for proprietary trading purposes.

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

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

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At September 30, 2014, Exelon and Generation had $1,600 million and $700 million of notional amounts of fixed-to-floating hedges outstanding, respectively, and $2,431 million and $781 million of notional amounts of floating-to-fixed hedges outstanding, respectively. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $7 million decrease in Exelon Consolidated pre-tax income for the nine months ended September 30, 2014. 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 currency hedges as of September 30, 2014.

	Generation					Other		Exelon
Description	**Derivatives Designated as Hedging Instruments**	**Economic Hedges**	**Proprietary Trading[(a)]**	**Collateral and Netting[(b)]**	**Subtotal**	**Derivatives Designated as Hedging Instruments**	**Economic Hedges**	**Total**
Mark-to-market derivative assets (current assets)	$ —	$ 4	$ 14	$ (14)	$ 4	$ —	$ —	$ 4
Mark-to-market derivative assets (noncurrent assets)	13	3	7	(10)	13	12	5	30
Total mark-to-market derivative assets	13	7	21	(24)	17	12	5	34
Mark-to-market derivative liabilities (current liabilities)	(1)	(7)	(11)	13	(6)	—	—	(6)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1)	(2)	(9)	9	(3)	(10)	(13)	(26)
Total mark-to-market derivative liabilities	(2)	(9)	(20)	22	(9)	(10)	(13)	(32)
Total mark-to-market derivative net assets (liabilities)	$ 11	$ (2)	$ 1	$ (2)	$ 8	$ 2	$ (8)	$ 2

(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) Represents the netting of fair value balances with the same counterparty and any associated cash collateral.

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, 2013:

	Generation					Other	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)	$ —	$ 3	$ 15	$ (19)	$ (1)	$ —	$ (1)
Mark-to-market derivative assets (noncurrent assets)	26	3	15	(13)	31	7	38
Total mark-to-market derivative assets	26	6	30	(32)	30	7	37
Mark-to-market derivative liabilities (current liabilities)	(1)	(1)	(18)	19	(1)	—	(1)
Mark-to-market derivative liabilities (noncurrent liabilities)	(10)	(1)	(13)	13	(11)	(4)	(15)
Total mark-to-market derivative liabilities	(11)	(2)	(31)	32	(12)	(4)	(16)
Total mark-to-market derivative net assets (liabilities)	$ 15	$ 4	$ (1)	$ —	$ 18	$ 3	$ 21

(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) Represents the netting of fair value balances with the same counterparty and any associated cash collateral.

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 September 30,			
	Income Statement Location	2014	2013	2014	2013
		Gain (Loss) on Swaps		Gain (Loss) on Borrowings	
Generation	Interest expense[(a)]	$ (4)	$ (4)	$ 1	$ (1)
Exelon	Interest expense	(8)	—	(6)	(6)

		Nine Months Ended September 30,			
	Income Statement Location	2014	2013	2014	2013
		Gain (Loss) on Swaps		Gain (Loss) on Borrowings	
Generation	Interest expense[(a)]	$ (12)	$ (13)	$ 1	$ —
Exelon	Interest expense	(3)	(12)	6	(2)

(a) For the three and nine months ended September 30, 2014, the loss on Generation swaps included $4 million and $12 million realized in earnings, respectively, with $2 million excluded from hedge effectiveness testing. For the three and nine months ended September 30, 2013, the loss on Generation swaps included $4 million and $12 million realized in earnings, respectively, with an immaterial amount excluded from hedge effectiveness testing.

During the first nine months of 2014, Exelon entered into $100 million and $75 million of notional amounts of fixed-to-floating fair value hedges related to interest rate swaps, which expire in 2019 and 2020, respectively. At September 30, 2014, Exelon and Generation had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $1,450 million and $550 million, with a derivative asset of $24 million and $12 million, respectively. At December 31, 2013, Exelon and Generation had outstanding fixed-to-floating fair value hedges related to interest rate swaps of $1,275 million and $550 million, with a derivative asset of $26 million and $23 million, respectively. During the three and nine months ended September 30, 2014, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $6 million and a $14 million gain, respectively. During the three and nine months ended September 30, 2013, the impact on the results of operations as a result of ineffectiveness from fair value hedges was immaterial.

Cash Flow Hedges. In connection with the DOE guaranteed loan for the Antelope Valley project financings, as discussed in Note 13 — Debt and Credit Agreements of the Exelon 2013 Form 10-K, Generation entered into a floating-to-fixed forward starting interest rate swap with an initial notional amount of $485 million and a mandatory early termination date by September 30, 2014. The interest rate swap was designated as a cash flow hedge, and as a result, unrealized losses of approximately $21 million have been recorded to Accumulated other comprehensive income, net on Exelon’s and Generation’s Consolidated Balance Sheets. During the third quarter of 2014, the interest rate swap was terminated consistent with the agreements. The unrealized loss of $21 million will be amortized into Interest expense on Exelon’s and Generation’s Consolidated Statement of Operations and Comprehensive Income over the term of the DOE loan.

During the third quarter of 2011, a subsidiary of Constellation entered into floating-to-fixed interest rate swaps to manage a portion of the interest rate exposure for anticipated long-term borrowings to finance Sacramento PV Energy. The swaps have a total notional amount of $28 million as of September 30, 2014 and expire in 2027. After the closing of the merger with Constellation, the swaps were re-designated as cash flow hedges. At September 30, 2014, the subsidiary had a $2 million derivative liability related to these swaps.

During the third quarter of 2012, a subsidiary of Exelon Generation entered into a floating-to-fixed interest rate swap to manage a portion of the interest rate exposure of anticipated long-term borrowings to finance Constellation Solar Horizons. The swap has a notional amount of $26 million as of September 30, 2014 and expires in 2030. This swap is designated as a cash flow hedge. At September 30, 2014, the subsidiary had a $1 million derivative asset related to the swap.

During the first quarter of 2014, a subsidiary of Exelon Generation entered into floating-to-fixed interest rate swaps to manage a portion of the interest rate exposure with long-term borrowings to finance ExGen Renewables I, LLC. See Note 10 — Debt and Credit Agreements for additional information regarding the financing. The swaps have a notional amount of $222 million as of September 30, 2014 and expire in 2020. The swaps are designated as cash flow hedges. At September 30, 2014, the subsidiary had a $1 million derivative liability related to the swaps.

During the first nine months of 2014, Exelon entered into $400 million of floating-to-fixed interest rate swaps to refinance existing debt. The swaps are designated as cash flow hedges. At September 30, 2014, Exelon had a $10 million derivative liability related to the swaps.

During the three and nine months ended September 30, 2014 and 2013, the impact on the results of operations as a result of ineffectiveness from cash flow hedges was immaterial.

Economic Hedges. During the first nine months of 2014, Exelon entered into $1,250 million of floating-to-fixed forward starting interest rate swaps to manage interest rate risks associated with anticipated future debt issuance related to the proposed merger with PHI. At September 30, 2014, Exelon had a $9 million derivative liability related to the swaps.

During the third quarter of 2014, a subsidiary of Exelon Generation entered into a floating-to-fixed interest rate swap to manage a portion of the interest rate exposure in connection with the long-term borrowings to finance ExGen Texas Power, LLC. See Note 10 — Debt and Credit Agreements for additional information regarding the financing. The swaps have a notional amount of $505 million as of September 30, 2014 and expire in 2019. At September 30, 2014, the subsidiary had a $3 million derivative liability related to the swaps.

At September 30, 2014, Exelon and Generation had $150 million in notional amounts of fixed-to-floating interest rate swaps that are marked-to-market. At September 30, 2014, Exelon and Generation had an immaterial derivative asset related to the swaps.

At September 30, 2014, Generation had $97 million in notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $322 million in notional amounts of foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

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

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 and 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. As of September 30, 2014 and December 31, 2013, $43 million and $10 million of cash collateral posted, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives, were associated with accrual positions, or as of the balance sheet date there were no positions to offset. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

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

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

(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 September 30, 2014:

	Generation				ComEd	Exelon
Derivatives	Economic Hedges	Proprietary Trading	Collateral and Netting[(a)]	Subtotal[(b)]	Economic Hedges[(c)]	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 3,230	$ 752	$ (3,242)	$ 740	$ —	$ 740
Mark-to-market derivative assets (noncurrent assets)	1,372	128	(1,006)	494	—	494
Total mark-to-market derivative assets	4,602	880	(4,248)	1,234	—	1,234
Mark-to-market derivative liabilities (current liabilities)	(3,017)	(755)	3,543	(229)	(14)	(243)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,129)	(136)	1,164	(101)	(164)	(265)
Total mark-to-market derivative liabilities	(4,146)	(891)	4,707	(330)	(178)	(508)
Total mark-to-market derivative net assets (liabilities)	$ 456	$ (11)	$ 459	$ 904	$ (178)	$ 726

(a) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as 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 $(96) million and $(50) million, respectively, and current and noncurrent liabilities are shown net of collateral of $(205) million and $(108) million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $459 million at September 30, 2014.

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

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2013:

	Generation				ComEd	Exelon
Description	Economic Hedges	Proprietary Trading	Collateral and Netting[(a)]	Subtotal[(b)]	Economic Hedges[(c)]	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 2,616	$ 1,476	$ (3,364)	$ 728	$ —	$ 728
Mark-to-market derivative assets (noncurrent assets)	1,344	285	(1,060)	569	—	569
Total mark-to-market derivative assets	3,960	1,761	(4,424)	1,297	—	1,297
Mark-to-market derivative liabilities (current liabilities)	(2,023)	(1,410)	3,292	(141)	(17)	(158)
Mark-to-market derivative liabilities (noncurrent liabilities)	(804)	(293)	988	(109)	(176)	(285)
Total mark-to-market derivative liabilities	(2,827)	(1,703)	4,280	(250)	(193)	(443)
Total mark-to-market derivative net assets (liabilities)	$ 1,133	$ 58	$ (144)	$ 1,047	$ (193)	$ 854

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

(a) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, and letters of credit. These are not reflected in the table above.
(b) Current and noncurrent assets are shown net of collateral of $84 million and $72 million, respectively, and current and noncurrent liabilities are shown net of collateral of $(12) million and $0 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $144 million at December 31, 2013.
(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Cash Flow Hedges (Exelon and Generation). As discussed previously, effective prior to the merger with Constellation, Generation de-designated all of its cash flow hedges relating to commodity price risk. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and is reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. Generation began recording prospective changes in the fair value of these instruments through current earnings from the date of de-designation. Approximately $67 million of these net pre-tax unrealized gains within accumulated OCI are expected to be reclassified from accumulated OCI during the next twelve months by Generation. Generation expects the settlement of the majority of its cash flow hedges will occur during 2014.

The tables below provide the activity of accumulated OCI related to cash flow hedges for the three months ended September 30, 2014 and 2013, 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 accumulated OCI, when combined with the impacts of the actual physical power sales, result in the ultimate recognition of net revenues at the contracted price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
Three Months Ended September 30, 2014	**Income Statement Location**	**Generation Energy-Related Hedges**	**Exelon Total Cash Flow Hedges**
Accumulated OCI derivative gain at June 30, 2014		$ 57[(a)]	$ 47
Effective portion of changes in fair value		—	(3)
Reclassifications from accumulated OCI to net income	Operating Revenues	(16)[(b)]	(16)
Accumulated OCI derivative gain at September 30, 2014		$ 41[(a)]	$ 28

(a) Excludes $13 million of losses, net of taxes, related to interest rate swaps and treasury rate locks as of September 30, 2014 and June 30, 2014.
(b) Amount is net of related income tax expense of $12 million for the three months ended September 30, 2014.

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

Nine Months Ended September 30, 2014	Income Statement Location	Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
		Energy-Related Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at December 31, 2013		$ 119[(a)]	$ 120
Effective portion of changes in fair value		—	(14)
Reclassifications from accumulated OCI to net income	Operating Revenues	(78)[(b)]	(78)
Accumulated OCI derivative gain at September 30, 2014		$ 41[(a)]	$ 28

(a) Excludes $13 million of losses and $5 million of losses, net of taxes, related to interest rate swaps and treasury locks as of September 30, 2014 and December 31, 2013, respectively.
(b) Amount is net of related income tax expense of $52 million for the nine months ended September 30, 2014.

Three Months Ended September 30, 2013	Income Statement Location	Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
		Energy-Related Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at June 30, 2013		$ 255[(a)]	$ 245
Effective portion of changes in fair value		—	2[(b)]
Reclassifications from accumulated OCI to net income	Operating Revenues	(51)[(c)]	(48)
Accumulated OCI derivative gain at September 30, 2013		$ 204[(a)]	$ 199

(a) Excludes $11 million of losses, net of taxes, related to interest rate swaps and treasury rate locks as of September 30, 2013 and June 30, 2013.
(b) Includes $2 million of gains, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks at Generation for the three months ended September 30, 2013.
(c) Amount is net of related income tax expense of $33 million for the three months ended September 30, 2013.

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

Nine Months Ended September 30, 2013	Income Statement Location	Total Cash Flow Hedge OCI Activity, Net of Income Tax — Generation: Energy-Related Hedges	Exelon: Total Cash Flow Hedges
Accumulated OCI derivative gain at December 31, 2012		$ 532[a][c]	$ 368
Effective portion of changes in fair value		—	25[d]
Reclassifications from accumulated OCI to net income	Operating Revenues	(328)[b][e]	(194)
Accumulated OCI derivative gain at September 30, 2013		$ 204[c]	$ 199

(a) Includes $133 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, as of December 31, 2012.
(b) Includes $133 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c) Excludes $11 million of losses and $20 million of losses, net of taxes, related to interest rate swaps and treasury rate locks as of September 30, 2013 and December 31, 2012, respectively.
(d) Includes $25 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.
(e) Amount is net of related income tax expense of $215 million for the nine months ended September 30, 2013.

During the three and nine months ended September 30, 2014 and 2013, Generation's former energy related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $28 million and a $130 million pre-tax gain and a $84 million and a $543 million pre-tax gain, respectively. Given that the cash flow hedges had primarily consisted of forward power sales and power swaps and did not include power and gas options or sales, the ineffectiveness of Generation's cash flow hedges was primarily the result of differences between the locational settlement prices of the cash flow hedges and the hedged generating units.

The effect of Exelon's former energy-related cash flow hedge activity on pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $28 million and $130 million pre-tax gain for the three and nine months ended September 30, 2014, and a $84 million and $324 million pre-tax gain for the three and nine months ended September 30, 2013. Neither Exelon nor Generation will incur changes in cash flow hedge ineffectiveness in future periods as all energy-related cash flow hedge positions were de-designated prior to the merger date.

Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, physical forward sales and purchases, but for which the fair value or cash flow hedge elections were not made. Additionally, Generation enters into interest rate derivative contracts and foreign exchange currency swaps ("treasury") to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars. Exelon entered into floating-to-fixed forward starting interest rate swaps to manage interest rate risks associated with anticipated future debt issuance related to the proposed merger with PHI. For the three and nine months ended September 30, 2014 and 2013, the following pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in operating revenues, purchased, power and fuel expense, or interest expense. For the three and nine months ended September 30, 2014 and 2013, the following pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in operating revenues or purchased power and fuel expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

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

	Generation				Intercompany Eliminations	HoldCo	Exelon
Three Months Ended September 30, 2014	**Operating Revenues**	**Purchased Power and Fuel**	**Interest Expense**	**Total**	**Operating Revenues[(a)]**	**Interest Expense**	**Total**
Change in fair value of commodity positions	$ 181	$ 19	$ —	$200	$ —	$ —	$ 200
Reclassification to realized at settlement of commodity positions	86	(23)	—	$ 63	—	—	63
Net commodity mark-to-market gains (losses)	267	(4)	—	263	—	—	263
Change in fair value of treasury positions	5	—	(3)	2	—	(8)	(6)
Reclassification to realized at settlement of treasury positions	(1)	—	—	(1)	—	—	(1)
Net treasury mark-to-market gains (losses)	4	—	(3)	1	—	(8)	(7)
Net mark-to-market gains (losses)	$ 271	$ (4)	$ (3)	$264	$ —	$ (8)	$ 256

	Generation				Intercompany Eliminations	HoldCo	Exelon
Nine Months Ended September 30, 2014	**Operating Revenues**	**Purchased Power and Fuel**	**Interest Expense**	**Total**	**Operating Revenues[(a)]**	**Interest Expense**	**Total**
Change in fair value of commodity positions	$ (795)	$ 302	$ —	$(493)	$ —	$ —	$(493)
Reclassification to realized at settlement of commodity positions	224	(207)	—	17	—	—	17
Net commodity mark-to-market gains (losses)	(571)	95	—	(476)	—	—	(476)
Change in fair value of treasury positions	1	—	(5)	(4)	—	(8)	(12)
Reclassification to realized at settlement of treasury positions	(2)	—	—	(2)	—	—	(2)
Net treasury mark-to-market gains (losses)	(1)	—	(5)	(6)	—	(8)	(14)
Net mark-to-market gains (losses)	$ (572)	$ 95	$ (5)	$(482)	$ —	$ (8)	$(490)

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

Three Months Ended September 30, 2013	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Interest Expense	Generation Total	Intercompany Eliminations Operating Revenues(a)	HoldCo Interest Expense	Exelon Total
Change in fair value of commodity positions	$ 175	$ 5	$ —	$180	$ —	$ —	$ 180
Reclassification to realized at settlement of commodity positions	41	25	—	66	—	—	66
Net commodity mark-to-market gains (losses)	216	30	—	246	—	—	246
Change in fair value of treasury positions	—	—	—	—	—	—	—
Reclassification to realized at settlement of treasury positions	—	—	—	—	—	—	—
Net treasury mark-to-market gains (losses)	—	—	—	—	—	—	—
Net mark-to-market gains (losses)	$ 216	$ 30	$ —	$246	$ —	$ —	$ 246

Nine Months Ended September 30, 2013	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Interest Expense	Generation Total	Intercompany Eliminations Operating Revenues(a)	HoldCo Interest Expense	Exelon Total
Change in fair value of commodity positions	$ 149	$ 74	$ —	$223	$ (6)	$ —	$ 217
Reclassification to realized at settlement of commodity positions	(15)	63	—	48	13	—	61
Net commodity mark-to-market gains (losses)	134	137	—	271	7	—	278
Change in fair value of treasury positions	—	—	(3)	(3)	—	—	(3)
Reclassification to realized at settlement of treasury positions	—	—	—	—	—	—	—
Net treasury mark-to-market gains (losses)	—	—	(3)	(3)	—	—	(3)
Net mark-to-market gains (losses)	$ 134	$ 137	$ (3)	$268	$ 7	$ —	$ 275

(a) Prior to the merger, the five-year financial swap contract between Generation and ComEd was de-designated. As a result, all prospective changes in fair value were recorded to operating revenues and eliminated in consolidation.

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

Proprietary Trading Activities (Exelon and Generation). For the three and nine months ended September 30, 2014 and 2013, 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 derivative contracts to hedge risk associated with the interest rate component of underlying commodity positions. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Location on Income Statement	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Change in fair value of commodity positions	Operating Revenues	$ (2)	$ —	$ (2)	$ 1
Reclassification to realized at settlement of commodity positions	Operating Revenues	(10)	(39)	(17)	(34)
Net commodity mark-to-market gains (losses)	Operating Revenues	(12)	(39)	(19)	(33)
Change in fair value of treasury positions	Operating Revenues	1	—	—	—
Reclassification to realized at settlement of treasury positions	Operating Revenues	—	(1)	1	(2)
Net treasury mark-to-market gains (losses)	Operating Revenues	1	(1)	1	(2)
Net mark-to-market gains (losses)	Operating Revenues	$ (11)	$ (40)	$ (18)	$ (35)

Credit Risk (Exelon, Generation, ComEd, PECO and BGE)

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

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of September 30, 2014. 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 excludes credit risk exposure from individual retail counterparties, uranium procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, further discussed in ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO and BGE of $11 million, $21 million and $34 million, respectively.

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

Rating as of September 30, 2014	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	$ 1,240	$ 88	$ 1,152	1	$ 423
Non-investment grade	23	7	16	—	—
No external ratings					
Internally rated — investment grade	302	—	302	1	180
Internally rated — non-investment grade	26	3	23	—	—
Total	$ 1,591	$ 98	$ 1,493	2	$ 603

Net Credit Exposure by Type of Counterparty	As of September 30, 2014
Financial institutions	$ 264
Investor-owned utilities, marketers, power producers	470
Energy cooperatives and municipalities	749
Other	10
Total	$ 1,493

(a) As of September 30, 2014, credit collateral held from counterparties where Generation had credit exposure included $94 million of cash and $4 million of letters of credit.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittal. 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 September 30, 2014, ComEd's net credit exposure to suppliers was immaterial.

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 2013 Form 10-K for additional information.

PECO's supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents PECO's net credit exposure. As of September 30, 2014, PECO had no net credit exposure with 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 September 30, 2014, PECO had credit exposure of $6 million 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 5 — Regulatory Matters 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 September 30, 2014, BGE had a net credit exposure of $23 million 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 September 30, 2014, BGE's credit exposure related to off-system sales was immaterial.

Collateral and Contingent-Related Features (Exelon, Generation, ComEd, PECO and BGE)

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

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

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	September 30, 2014	December 31, 2013
Gross Fair Value of Derivative Contracts Containing this Feature[(a)]	$ (997)	$ (1,056)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements[(b)]	694	846
Net Fair Value of Derivative Contracts Containing This Feature[(c)]	$ (303)	$ (210)

(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 $669 million and letters of credit posted of $389 million and cash collateral held of $169 million and letters of credit held of $12 million as of September 30, 2014 for counterparties with derivative positions. Generation had cash collateral posted of $72 million and letters of credit posted of $364 million and cash collateral held of $206 million and letters of credit held of $34 million at December 31, 2013 for counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e., to BB+ by S&P or Ba1 by Moody's), Generation would have been required to post additional collateral of $2.1 billion and $2.0 billion as of September 30, 2014 and December 31, 2013, 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 September 30, 2014, Generation's and Exelon's swaps were in an asset position, with a fair value of $8 million and $2 million, respectively.

See Note 24 — Segment Information of the Exelon 2013 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 September 30, 2014, ComEd held approximately $2 million from suppliers for the purpose of 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 September 30, 2014, 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. See Note 3 — Regulatory Matters of the Exelon 2013 Form 10-K for additional information.

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

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 September 30, 2014, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of September 30, 2014, PECO could have been required to post approximately $25 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 September 30, 2014, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of September 30, 2014, BGE could have been required to post approximately $47 million of collateral to its counterparties.

10. Debt and Credit Agreements (Exelon, Generation, ComEd, PECO and BGE)

Short-Term Borrowings

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool.

The Registrants had the following amounts of commercial paper borrowings outstanding as of September 30, 2014 and December 31, 2013:

Commercial Paper Borrowings	September 30, 2014	December 31, 2013
Exelon Corporate	$ —	$ —
Generation	—	—
ComEd	528	184
PECO	—	—
BGE	20	135

Credit Facilities

Exelon had bank lines of credit under committed credit facilities at September 30, 2014 for short-term financial needs, as follows:

Type of Credit Facility	Amount[(a)] (In billions)	Expiration Dates	Capacity Type
Exelon Corporate			
Syndicated Revolver[(b)]	$ 0.5	May 2019	Letters of credit and cash
Generation			
Syndicated Revolver	5.1	May 2019	Letters of credit and cash
Syndicated Revolver	0.2	August 2018	Letters of credit and cash
Bilateral	0.3	December 2015 and March 2016	Letters of credit and cash
Bilateral	0.1	January 2015	Letters of credit
Bilateral	0.1	October 2014	Letters of credit and cash
ComEd			
Syndicated Revolver	1.0	March 2019	Letters of credit and cash
PECO			
Syndicated Revolver[(b)]	0.6	May 2019	Letters of credit and cash
BGE			
Syndicated Revolver[(b)]	0.6	May 2019	Letters of credit and cash
Total	$ 8.5		

(a) Excludes additional credit facility agreements for Generation, ComEd, PECO and BGE with aggregate commitments of $50 million, $34 million, $34 million and $5 million, respectively, arranged with minority and community banks located primarily within ComEd's, PECO's and BGE's service territories. These facilities expired on October 17, 2014 and were renewed at the same amount through October 16, 2015. These facilities are solely utilized to issue letters of credit. As of September 30, 2014, letters of credit issued under these agreements for Generation, ComEd, PECO and BGE totaled $9 million, $18 million, $21 million and $1 million, respectively. Also, excludes the unsecured bridge credit facility of $3.9 billion to support the PHI transaction discussed below, as well as, applicable asset divestitures.

(b) Includes credit facilities for Exelon Corporate, PECO and BGE with aggregate commitments of $22 million, $27 million and $27 million, respectively, that expire in August 2018.

As of September 30, 2014, there were no borrowings under the Registrants' credit facilities.

On March 28, 2014, ComEd extended for an additional year the expiration date of its unsecured revolving credit facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement expires on March 28, 2019. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to extend the facility for ComEd were not material.

On October 24, 2014, a $100 million bilateral CENG credit facility was amended and extended for an additional year. This facility has been utilized by CENG to fund working capital and capital projects and obtain letters of credit.

On May 30, 2014, each of Exelon Corporate, Generation, PECO and BGE extended the expiration date of its unsecured revolving credit facility with aggregate bank commitments of $500 million, $5.3 billion, $600 million, $600 million, respectively into May 2019, with the exception of a cumulative amount of $315 million in commitments, which expire in August 2018. Costs incurred to extend the facilities were not material.

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

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's and BGE's credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular Registrant's credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5,7.5, 0.0 and 0.0 basis points for prime based borrowings and 127.5, 127.5, 107.5, 90.0 and 100.0 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of the borrower.

Credit Agreements

In May 2014, concurrently and in connection with entering into the agreement to acquire PHI, Exelon entered into a credit facility to which the lenders committed to provide Exelon a 364-day senior unsecured bridge credit facility of $7.2 billion to support the contemplated transaction and provide flexibility for timing of permanent financing. The bridge credit facility was subsequently reduced to $3.9 billion as a result of the June 2014 equity issuances discussed below, as well as, applicable asset divestitures. During the three and nine months ended September 30, 2014, Exelon recorded $11 million and $20 million to interest expense in connection with the bridge facility, respectively. It is not currently expected that Exelon will be required to draw upon this credit facility.

Long-Term Debt

Issuance of Long-Term Debt

During the nine months ended September 30, 2014, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Junior Subordinated Notes	2.500%	June 1, 2024	$ 1,150	Used to finance a portion of the acquisition of PHI and for general corporate purposes
Generation	Nuclear Fuel Purchase Contract	3.350%	June 30, 2018	$ 38	Used for procurement of uranium
Generation	ExGen Renewables I Project Financing[(a)]	LIBOR + 4.250%	February 6, 2021	$ 300	Used for general corporate purposes
Generation	ExGen Texas Power Project Financing[(a)]	LIBOR + 4.750%	September 18, 2021	$ 675	Used for general corporate purposes
Generation	Energy Efficiency Project Financing	4.120%	December 31, 2015	$ 12	Funding to install energy conservation measures in Washington, DC
Generation	AVSR DOE Project Financing	3.056% - 3.143%	January 5, 2037	$ 125	Used for Antelope Valley solar development
Generation	Nuclear Fuel Purchase Contract	3.250%	June 30, 2018	$ 32	Used for procurement of uranium
ComEd	First Mortgage Bonds Series 115	2.150%	January 15, 2019	$ 300	Used to refinance existing mortgage bonds
ComEd	First Mortgage Bonds Series 116	4.700%	January 15, 2044	$ 350	Used to refinance existing mortgage bonds
PECO	First and Refunding Mortgage Bonds	4.150%	October 1, 2044	$ 300	Used to refinance existing mortgage bonds and general corporate purposes

(a) See ExGen Renewables I Project Financing and ExGen Texas Power Project Financing discussed below.

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. Net proceeds from the issuance were $1.11 billion, net of a $35 million underwriter fee. The net proceeds are expected to be used to finance a portion of the acquisition of PHI and for general corporate purposes.

Each equity unit represents an undivided beneficial ownership interest in Exelon’s 2.50% junior subordinated notes due in 2024 and a forward equity purchase contract which settles in 2017. The junior subordinated notes are expected to be remarketed in 2017. In connection with the remarketing, Exelon may modify the maturity date of the notes to a date earlier than June 1, 2024 but not earlier than June 1, 2020, remove redemption provisions of the notes, or change the interest rate on the notes, including changing the interest rate from fixed to floating. Investors that participate in the remarketing receive the remarketing proceeds and may use those funds to either settle the equity forward upon settlement date or invest in the remarketed debt and use other funds for the share purchase. Exelon intends to use the remarketing proceeds to repay debt issued or for other corporate purposes as soon as practical following such settlements. If the remarketing fails, holders of the notes will have the right to put their notes to Exelon for an amount equal to the principal amount of notes held by such holder plus accrued interest. The equity units carry a total annual distribution rate of 6.5%, which is comprised of a quarterly coupon rate of interest of 2.5% and a quarterly contract payment of 4.0% (contract payments).

Each purchase contract obligates the holder to purchase, and Exelon to sell, for $50.00 a number of shares of Exelon’s common stock in accordance with the conversion ratios set forth below:

- If the market price equals or exceeds $43.7484, then 1.1429 shares.
- If the market price is less than $43.7484 but greater than $35.00, a number of shares of common stock having a value, based on the market price, equal to $50.00
- If the market price is less than or equal to $35.00, then 1.4286 shares.

A holder’s ownership interest in the notes is pledged to Exelon to secure the holder’s obligation under the related forward equity purchase contract. If a holder of the forward equity purchase contract chooses at any time to no longer be a holder of the notes, such holder’s obligation under the purchase contract must be secured by a U.S. Treasury security.

At the time of issuance, the $1.15 billion of junior subordinated notes were recorded within Long-term debt on Exelon’s Consolidated Balance Sheet. Additionally, at the time of issuance, the present value of the contract payments of $131 million were recorded to Long-term debt, representing the obligation to make contract payments, with an offsetting reduction to Common stock. The obligation for the contract payments will be accreted to interest expense over the 3 year period ending in 2017 in Exelon’s Consolidated Statement of Operations and Comprehensive Income. The Long-term debt recorded for the contract payments is considered a non-cash financing transaction that was excluded from Exelon’s Consolidated Statements of Cash Flows. Until settlement of the equity purchase contract, earnings per share dilution resulting from the equity unit issuance will be determined under the treasury stock method.

Non-Recourse Debt

The following describes certain indebtedness that was incurred by Generation’s project company subsidiaries during the nine months ended September 30, 2014. The indebtedness described below is a component of the total $2.7 billion net book value of certain generating facilities pledged as collateral as of September 30, 2014. All associated project financing liabilities are non-recourse to Exelon and Generation.

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

ExGen Renewables Energy I, LLC

On February 6, 2014, ExGen Renewables I, LLC (EGR), an indirect subsidiary of Exelon and Generation, borrowed $300 million aggregate principal amount pursuant to a non-recourse senior secured loan, due February 6, 2021. The loan bears interest at a variable rate equal to LIBOR plus 4.25%, subject to a 1% LIBOR floor. EGR indirectly owns Continental Wind LLC (Continental Wind). In addition to the financing, EGR entered into interest rate swaps with a notional amount of $240 million at an interest rate of 2.03% to manage a portion of the interest rate exposure in connection with the financing, see Note 9 — Derivative Financial Instruments for additional information regarding interest rate swaps.

ExGen Texas Power, LLC

On September 18, 2014, ExGen Texas Power, LLC (EGTP), an indirect subsidiary of Exelon and Generation, borrowed $675 million aggregate principal amount pursuant to a non-recourse senior secured term loan, 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. 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 a floating-to-fixed interest rate swap with an initial notional amount of approximately $505 million at an interest rate of 2.34% to manage a portion of the interest rate exposure in connection with this financing. See Note 9 — Derivative Financial Instruments for additional information regarding interest rate swaps.

During the nine months ended September 30, 2013, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Upstream Gas Lending Agreement	2.210 - 2.440%	July 22, 2016	$ 5	Used to fund Upstream gas activities
Generation	AVSR DOE Project Financing	2.535 - 3.353%	January 5, 2037	$ 204	Funding for Antelope Valley Solar Development
Generation	Energy Efficiency Project Financing	4.400%	August 31, 2014	$ 9	Funding to install energy conservation measures in Beckley, West Virginia
Generation	Continental Wind Senior Secured Notes	6.000%	February 28, 2033	$ 613	Used for general corporate purposes
ComEd	First Mortgage Bonds Series 114	4.600%	August 15, 2043	$ 350	Used to repay outstanding commercial paper obligations and for general corporate purposes
PECO	First and Refunding Mortgage Bonds	1.200%	October 15, 2016	$ 300	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
PECO	First and Refunding Mortgage Bonds	4.800%	October 15, 2043	$ 250	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
BGE	Senior Notes	3.350%	July 1, 2023	$ 300	Used to partially refinance Notes due July 1, 2013 and for general corporate purposes

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

Retirement and Redemptions of Current and Long-Term Debt

During the nine months ended September 30, 2014, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Generation	2003 Senior Notes	5.35%	January 15, 2014	$ 500
Generation	Pollution Control Loan	4.10%	July 1, 2014	$ 20
Generation	Continental Wind Project Financing	6.00%	February 28, 2033	$ 20
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 2
Generation	ExGen Renewables I Project Financing	3mL + 4.25%	February 6, 2021	$ 3
Generation	AVSR DOE Project Financing	2.33% - 3.55%	January 5, 2037	$ 4
Generation	Clean Horizons Solar	2.56%	September 7, 2030	$ 1
Generation	Sacramento Solar Project Financing	2.56%	December 31, 2030	$ 1
Generation	Energy Efficiency Project Financing	4.40%	August 31, 2014	$ 9
ComEd	Mortgage Bonds Series 110	1.63%	January 15, 2014	$ 600
ComEd	Pollution Control Series 1994C	5.85%	January 15, 2014	$ 17
BGE	Rate Stabilization Bonds	5.72%	April 1, 2017	$ 35

On October 1, 2014, PECO retired $250 million aggregate principal of its 5.000% First and Refunding Mortgage Bonds due October 1, 2014.

On October 6, 2014, Generation paid down $11 million of principal and interest of its 3.056% - 3.143% AVSR Solar loan.

During the nine months ended September 30, 2013, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Generation	Kennett Square Capital Lease	7.830%	September 20, 2020	$ 2
Generation	Solar Revolver	1.930 - 1.950%	July 7, 2014	$ 18
Generation	Clean Horizons Solar Project Financing	2.563%	September 7, 2030	$ 1
Generation[(a)]	Series A Junior Subordinated Debentures	8.625%	June 15, 2063	$ 450
ComEd	First Mortgage Bonds Series 92	7.625%	April 15, 2013	$ 125
ComEd	First Mortgage Bonds Series 94	7.500%	July 1, 2013	$ 127
BGE	Senior Notes	6.125%	July 1, 2013	$ 400
BGE	Rate Stabilization Bonds	5.720%	April 1, 2017	$ 33

(a) Represents debt obligations assumed by Exelon as part of the Constellation merger on March 12, 2012 that became callable at face value on June 15, 2013. Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets. The debentures were redeemed and the intercompany loan agreements repaid on June 15, 2013.

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

11. Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

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

For the Three Months Ended September 30, 2014	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	1.1	0.7	5.0	0.1	4.6
Qualified nuclear decommissioning trust fund income	(0.3)	(0.4)	—	—	—
Domestic production activities deduction	(2.4)	(3.2)	—	—	—
Health care reform legislation	—	—	0.2	—	0.2
Amortization of investment tax credit, net deferred taxes	(1.0)	(1.2)	(0.3)	(0.1)	(0.3)
Plant basis differences	(0.8)	—	—	(11.3)	0.5
Production tax credits and other credits	(1.9)	(2.4)	—	—	—
Noncontrolling interest	(1.2)	(1.6)	—	—	—
Other	(0.3)	(1.4)	0.1	(0.1)	(1.2)
Effective income tax rate	28.2%	25.5%	40.0%	23.6%	38.8%

For the Nine Months Ended September 30, 2014	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	0.5	(1.4)	5.0	0.3	4.9
Qualified nuclear decommissioning trust fund income	2.0	3.6	—	—	—
Domestic production activities deduction	(2.7)	(4.8)	—	—	—
Health care reform legislation	0.1	—	0.2	—	0.2
Amortization of investment tax credit, net deferred taxes	(1.1)	(1.7)	(0.3)	(0.1)	(0.3)
Plant basis differences	(1.6)	—	(0.3)	(11.0)	0.5
Production tax credits and other credits	(2.1)	(3.7)	—	—	—
Noncontrolling interest	(1.4)	(2.6)	—	—	—
Other	(1.5)	(2.5)	0.1	0.1	(0.5)
Effective income tax rate	27.2%	21.9%	39.7%	24.3%	39.8%

For the Three Months Ended September 30, 2013	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	3.0	2.6	5.4	(0.3)	5.6
Qualified nuclear decommissioning trust fund income	3.5	5.3	—	—	—
Tax exempt income	(0.2)	(0.3)	—	—	—
Health care reform legislation	0.1	—	0.4	—	0.2
Amortization of investment tax credit, net deferred taxes	(1.5)	(2.1)	(0.4)	(0.1)	(0.3)
Plant basis differences	(0.8)	—	(0.4)	(6.9)	0.1
Production tax credits and other credits	(2.2)	(3.3)	—	—	—
Other	0.5	0.1	0.3	(0.1)	(0.2)
Effective income tax rate	37.4%	37.3%	40.3%	27.6%	40.4%

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

For the Nine Months Ended September 30, 2013	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	5.3	1.8	5.2	1.9	5.6
Qualified nuclear decommissioning trust fund income	3.2	5.1	—	—	—
Tax exempt income	(0.2)	(0.3)	—	—	—
Health care reform legislation	0.1	—	0.9	—	0.2
Amortization of investment tax credit, net deferred taxes	(2.3)	(3.4)	(0.8)	(0.1)	(0.3)
Plant basis differences	(1.7)	—	(1.2)	(7.3)	(0.4)
Production tax credits and other credits	(2.4)	(3.9)	—	—	—
Other	0.2	1.1	0.8	—	—
Effective income tax rate	37.2%	35.4%	39.9%	29.5%	40.1%

Accounting for Uncertainty in Income Taxes

Exelon, Generation, ComEd, PECO, and BGE have $1,808 million, $1,342 million, $151 million, $44 million, and $0 million, of unrecognized tax benefits as of September 30, 2014, respectively, and $2,175 million, $1,415 million, $324 million, $44 million, and $0 million, of unrecognized tax benefits as of December 31, 2013, respectively. The unrecognized tax benefits as of September 30, 2014 reflect a decrease at Exelon and ComEd primarily attributable to the like-kind exchange and the lease termination position discussed below and a decrease at Generation primarily due to the expiration of both federal and state statutes of limitation in September 2014.

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

Nuclear Decommissioning Liabilities (Exelon and Generation)

AmerGen filed income tax refund claims taking the position that nuclear decommissioning liabilities assumed as part of its acquisition of nuclear power plants are taken into account in determining the tax basis in the assets it acquired. The additional basis results primarily in reduced capital gains or increased capital losses on the sale of assets in nonqualified decommissioning funds and increased tax depreciation and amortization deductions. The IRS disagrees with this position and has disallowed the claims. In November 2008, Generation received a final determination from the Appeals division of the IRS (IRS Appeals) disallowing AmerGen's refund claims. Generation filed a complaint in the United States Court of Federal Claims on February 20, 2009 to contest this determination. During the first and second quarters of 2013, AmerGen and the DOJ completed and filed cross motions for summary judgment. On September 17, 2013, the Court granted the government's motion denying AmerGen's claims for refund. In the first quarter of 2014, Exelon filed an appeal of the decision to the United States Court of Appeals for the Federal Circuit.

Due to the possibility of final resolution through an appellate decision, Generation continues to believe that it is reasonably possible that the total amount of unrecognized tax benefits may significantly decrease in the next 12 months.

Settlement of Income Tax Audits

As of September 30, 2014, Exelon and Generation have approximately $180 million of unrecognized state tax benefits that could significantly decrease within the 12 months after the reporting date as a result of completing federal and state audits and expected statute of limitation expirations that if recognized would decrease the effective tax rate. In September 2014, uncertain income tax positions were effectively settled due to the expiration of both federal and state statutes of limitation resulting in a reduction to unrecognized tax benefit of $75 million at Generation. Through the end of the third quarter, the effective settlement of unrecognized tax benefits has resulted in reduced tax expense of $90 million at Generation.

Other Income Tax Matters

Like-Kind Exchange

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

Exelon has been unable to reach agreement with the IRS regarding the dispute over the like-kind exchange position. The IRS has asserted that the Exelon purchase and leaseback transaction is substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a "listed transaction" that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS has asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities does not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS has also asserted a penalty of approximately $87 million for a substantial understatement of tax.

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

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

In accordance with applicable accounting standards, Exelon is required to assess whether it is more-likely-than-not that it will prevail in litigation. Exelon continues to believe that its transaction is not a SILO and that it has a strong case on the merits. However, in light of the Consolidated Edison decision and Exelon's current determination that settlement is unlikely, Exelon has concluded that subsequent to December 31, 2012, it is no longer more-likely-than-not that its position will be sustained. As a result, in the first quarter of 2013 Exelon recorded a non-cash charge to earnings of approximately $265 million, which represents the amount of interest expense (after-tax) and incremental state income tax expense for periods through March 31, 2013 that would be payable in the event that Exelon is unsuccessful in litigation. Of this amount, approximately $170 million was recorded at ComEd. Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity. As such, ComEd recorded on its consolidated balance sheet as of March 31, 2013, a $172 million receivable and non-cash equity contributions from Exelon. Exelon and ComEd will continue to accrue interest on the unpaid tax liabilities related to the uncertain tax position, and the charges arising from future interest accruals are not expected to be material to the annual operating earnings of Exelon or ComEd. In addition, ComEd will continue to record non-cash equity contributions from Exelon in the amount of the net after-tax interest charges attributable to ComEd in connection with the like-kind exchange position. Exelon continues to believe that it is unlikely that the IRS's assertion of penalties will ultimately be sustained and therefore no liability for the penalty has been recorded.

On September 30, 2013, the IRS issued a notice of deficiency to Exelon for the like-kind exchange position. Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the issue. The litigation could take three to five years including appeals, if necessary. Decisions in the Tax Court are not controlled by the Federal Circuit's decision in Consolidated Edison.

In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable as of September 30, 2014 may be as much as $800 million, of which approximately $310 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless, and the balance at Exelon. Litigation could take several years such that the estimated cash and interest impacts would likely change by a material amount.

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. The termination will result in a 2014 tax payment of approximately $285 million by Exelon, including approximately $155 million by ComEd representing the remaining gain deferred pursuant to the like-kind exchange transaction. In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, Exelon will be required to pay the full amount of tax and after-tax interest discussed in the preceding paragraph but will ultimately be entitled to a refund of the 2014 tax payment. See Note 7 — Impairment of Long-Lived Assets for further details.

Accounting for Generation Repairs (Exelon and Generation)

On April 30, 2013, the IRS issued Revenue Procedure 2013-24 providing guidance for determining the appropriate tax treatment of costs incurred to repair electric generation assets. Generation will change its method of accounting for deducting repairs in accordance with this guidance beginning with its 2014 tax year. Generation has estimated that adoption of the new method will result in a non-recurring cash tax detriment of approximately $100 - $120 million.

12. Nuclear Decommissioning (Exelon and Generation)

Nuclear Decommissioning Asset Retirement Obligations

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

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

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets from December 31, 2013 to September 30, 2014:

Nuclear decommissioning ARO at December 31, 2013[(a)]	$4,855
Consolidation of CENG[(b)]	1,684
Accretion expense	243
Net decrease due to changes in, and timing of, estimated cash flows	(125)
Costs incurred to decommission retired plants	(5)
Nuclear decommissioning ARO at September 30, 2014[(a)]	$6,652

(a) Includes $9 million as the current portion of the ARO at September 30, 2014 and December 31, 2013 which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.
(b) Includes the fair value of the CENG ARO liability as of April 1, 2014, the date of consolidation. See Note 6 — Investment in Constellation Energy Nuclear Group, LLC for additional information.

During the nine months ended September 30, 2014, Generation's ARO increased by approximately $1.8 billion. The increase is largely driven by the recording of an ARO on Exelon's and Generation's Consolidated Balance Sheets at fair value upon consolidation of CENG during the second quarter (see Note 6 — Investment in Constellation Energy Nuclear Group, LLC). The fair value of the ARO was considered an initial estimate requiring updates through the use of a third party engineering firm with corresponding adjustments expected to be recorded by the end of 2014. The ARO valuations for the Calvert Cliffs and Nine Mile Point nuclear units were updated during the third quarter of 2014 resulting in a $17 million reduction to the originally recorded ARO. The ARO valuation for the Ginna nuclear unit will be updated during the fourth quarter of 2014 once cost studies are completed. The ARO was also adjusted in the third quarter of 2014 to reflect the impacts of a reduction in estimated escalation rates, primarily for labor and energy costs, offset in part by an increase in the estimated costs to decommission the Byron and Braidwood nuclear units resulting from the completion of updated decommissioning costs studies received during 2014 as part of the annual assessment. The decrease in the ARO due to the changes in, and timing of, estimated cash flows were primarily offset within Property, plant and equipment on Exelon's and Generation's Consolidated Balance Sheets. Approximately $16 million of the reduction in the ARO resulted in a credit to income, which is included in Operating and maintenance expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

During the nine months ended September 30, 2013, Generation's ARO increased by approximately $51 million. The increase is largely driven by an increase in the estimated costs to decommission the Limerick and Three Mile Island nuclear units resulting from the completion of updated decommissioning costs studies received during 2013 and an increase for accretion of the obligation. These increases in the ARO were offset by decreases to the ARO due to changes in long-term escalation rates, primarily for labor and energy costs, as well as changes in the timing of the future nominal cash flows coupled with the fact that cash flows affected by this change in timing are re-measured and discounted at current CARFRs, which have increased from the prior year. The decrease in the ARO due to the changes in, and timing of, estimated cash flows were entirely offset by decreases in Property, plant and equipment within Exelon's and Generation's Consolidated Balance Sheets.

Nuclear Decommissioning Trust Fund Investments

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

The NDT funds associated with the former ComEd, former PECO, former AmerGen and the CENG units have been funded with amounts collected from ComEd customers, PECO customers, and the previous owners of the former AmerGen and the CENG plants, respectively. Based on an ICC order, ComEd ceased collecting amounts from its customers to pay for decommissioning costs. 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. The most recent rate adjustment occurred on January 1, 2013, and the effective rates currently yield annual collections of approximately $24 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2018. With respect to the former AmerGen and CENG units, Generation does not collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from customers. Apart from the contributions made to the NDT funds from amounts previously collected from ComEd and currently collected from PECO customers, Generation has not made contributions to the NDT funds.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been transferred to a third party (see Zion Station Decommissioning below) and the CENG units, where any shortfall is required to be funded by both Generation and EDF. Generation, through PECO, has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO, and likewise Generation, will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds, on an aggregate basis for all former PECO units, compared to decommissioning obligations, as well as 5% of any additional shortfalls. The initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from ComEd customers for the former ComEd units or from the previous owners of the former AmerGen and CENG units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after all decommissioning has been completed are required to be refunded to ComEd's or PECO's customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to the former AmerGen units and CENG units, Generation retains any funds remaining after decommissioning. However, in connection with CENG's acquisition of the Nine Mile Point and Ginna plants and settlements with certain regulatory agencies, CENG is subject to certain conditions pertaining to nuclear decommissioning trust funds that, if met, could possibly result in obligations to make payments to certain third parties (clawbacks). For Nine Mile Point and Ginna, the clawback provisions are triggered only in the event that the required decommissioning activities are discontinued or not started or completed in a timely manner. In the event that the clawback provisions are triggered for Nine Mile Point, then, depending upon the triggering event, an amount equal to 50% of the total amount withdrawn from the funds for non-decommissioning activities or 50% of any excess funds in the trust funds above the amounts required for decommissioning (including spent fuel management and decommissioning) is to be paid to the Nine Mile Point sellers. In the event that the clawback provisions are triggered for Ginna, then an amount equal to any estimated cost savings realized by not completing any of the required decommissioning activities is to be paid to the Ginna sellers. Generation expects to comply with applicable regulations and timely commence and complete all required decommissioning activities.

At September 30, 2014 and December 31, 2013, Exelon and Generation had NDT fund investments totaling $10,349 million and $8,071 million, respectively.

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

The following table provides unrealized gains (losses) on NDT funds for the three and nine months ended September 30, 2014 and 2013:

	Exelon and Generation			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net unrealized gains (losses) on decommissioning trust funds — Regulatory Agreement Units[(a)]	$ (107)	$ 103	$ 126	$ 196
Net unrealized gains (losses) on decommissioning trust funds — Non-Regulatory Agreement Units[(b)(c)]	(41)	46	100	70

(a) Net unrealized gains (losses) related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets and Noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
(b) Excludes $7 million of net unrealized gains and $9 million of net unrealized losses related to the Zion Station pledged assets for the three months ended September 30, 2014 and 2013, respectively, and $27 million of net unrealized gains and $5 million of net unrealized losses related to the Zion Station pledged assets for the nine months ended September 30, 2014 and 2013, respectively. Net unrealized gains (losses) 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 (losses) 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.

See Note 3 — Regulatory Matters and Note 25 — Related Party Transactions of the Exelon 2013 Form 10-K for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning. On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions, under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. See Note 15 — Asset Retirement Obligations of the Exelon 2013 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, will be 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, 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 $85 million, which is included within the nuclear decommissioning ARO at September 30, 2014. Generation also has retained NDT assets to fund its obligation to maintain and transfer the SNF at Zion Station 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 payable to ZionSolutions, and withdrawals by ZionSolutions at September 30, 2014 and December 31, 2013:

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

	Exelon and Generation	
	September 30, 2014	December 31, 2013
Carrying value of Zion Station pledged assets	$ 365	$ 458
Payable to Zion Solutions[(a)]	334	414
Current portion of payable to Zion Solutions[(b)]	74	109
Withdrawals by Zion Solutions to pay decommissioning costs[(c)]	618	498

(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) Cumulative withdrawals since September 1, 2010.

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. On April 1, 2013, Generation submitted its NRC-required biennial decommissioning funding status report as of December 31, 2012. As of December 31, 2012, Generation provided adequate funding assurance for all of its units, including Limerick Unit 1, where Generation has in place a $115 million parent guarantee to cover the NRC minimum funding assurance requirements. On October 2, 2013, the NRC issued summary findings from the NRC Staff’s review of the 2013 decommissioning funding status reports for all 104 operating reactors, including the Generation operating units. Based on that review, the NRC Staff determined that Generation provided decommissioning funding assurance under the NRC regulations for all of its operating units, including Limerick Unit 1. On March 26, 2014, in accordance with a NRC requirement with respect to units involved in a merger or acquisition, CENG submitted its NRC-required decommissioning funding status report as of December 31, 2013 and no additional financial assurance was required.

On March 31, 2014, Generation submitted its NRC required annual decommissioning funding report as of December 31, 2013 for shutdown reactors. This submittal also included the required updated financial tests for the Limerick Unit 1 parent guarantee. There was no change to the amount of the parent guarantee, or the funding status of these reactors. Adequate decommissioning funding assurance is in place for all reactors owned by Generation. On October 20, 2014, the NRC issued a 20 year renewal of the Limerick Units 1 and 2 operating licenses. With the additional 20 years of operating life for Limerick Unit 1, the parent guarantee is no longer required to provide adequate funding assurance. Generation intends to send to the NRC a notice of cancellation, which is required 120 days prior to cancellation.

On January 31, 2013, Generation received a letter from the NRC indicating that the NRC has identified potential “apparent violations” of its regulations because of alleged inaccuracies in the Decommissioning Funding Status reports for 2005, 2006, 2007, and 2009. The NRC asserted that Generation’s status reports deliberately reflected cost estimates for decommissioning its nuclear plants that were less than what the NRC says are the minimum amounts required by NRC regulations. The January 31, 2013 letter from the NRC does not take issue with Generation's current funding status, and as reflected in Generation's April 1, 2013 decommissioning funding status report referenced above, Generation continues to provide adequate funding assurance for each of its units. Generation met with the NRC on April 30, 2013 for a pre-decisional enforcement conference to provide additional information to explain why Generation believes that it complied with the regulatory requirements and did not deliberately or otherwise provide incomplete or inaccurate information in its decommissioning funding status reports. On May 1, 2014, the NRC issued its final determination. Although the NRC determined that these historical status reports did not provide complete and accurate information, the violation of the regulatory requirements was not a deliberate violation. The NRC noted the low safety significance and Generation's corrective actions to satisfy the NRC Staff's expectations and issued a Severity Level IV violation, with no monetary penalty. A Severity Level IV violation is the lowest level of violation.

In addition, on June 24, 2013, Exelon received a subpoena from the SEC requesting that Exelon provide the SEC with certain documents generally relating to Exelon and Generation's reporting and funding of the future decommissioning of Generation's nuclear power plants. Exelon and Generation have cooperated with the SEC and provided the requested documents. On February 13, 2014, Exelon received a letter from the SEC confirming that it had concluded its investigation and that no further action was anticipated based on information provided by Exelon.

13. Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees.

As a result of the consolidation of CENG into Generation on April 1, 2014, the obligations associated with CENG's pension and other postretirement plans are reflected in the disclosures below based on an April 1, 2014 valuation adjusted for subsequent activity. The plans include essentially all former employees at CENG. Exelon assumed sponsorship of the CENG pension and other postretirement benefit plans on July 14, 2014. CENG will fund the underfunded balances of the pension and other post retirement benefit plans measured at July 14, 2014 on an agreed payment schedule or upon the occurrence of certain specified events, such as EDF's disposition of a majority of its interest in CENG. Payments received from CENG related to the funded plans will be contributed to the appropriate benefit trusts.

Defined Benefit Pension and Other Postretirement Benefits

During the first quarter of 2014, Exelon received an updated valuation of several of its pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2014. This valuation resulted in an increase to the pension obligation of $35 million and an increase to the other postretirement benefit obligation of $12 million. Additionally, accumulated other comprehensive loss increased by approximately $12 million (after tax), regulatory assets increased by approximately $34 million, and regulatory liabilities increased by approximately $5 million. During the second quarter of 2014, Exelon received an updated valuation for the remainder of its pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2014. This valuation resulted in an increase to the pension obligation of $13 million and an increase to the other postretirement benefit obligation of $3 million. Additionally, accumulated other comprehensive loss increased by approximately $1 million (after tax) and regulatory assets increased by approximately $15 million.

In April 2014, Exelon announced plan design changes for certain other postretirement benefit plans, which required an interim remeasurement of the benefit obligation for those plans using assumptions as of April 30, 2014, including updated discount rates and asset values. The remeasurement resulted in a decrease in the net periodic benefit costs for other postretirement benefits of approximately $149 million for the period May 2014 through December 2014 as compared to the net periodic benefit costs that were anticipated based on the January 1, 2014 valuation. The remeasurement resulted in a decrease in Exelon's non-pension postretirement benefit obligations, regulatory assets, and accumulated other comprehensive loss of approximately $790 million, $240 million, and $259 million (after tax), respectively, and an increase in regulatory liabilities of approximately $125 million.

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

The following tables present the components of Exelon's net periodic benefit costs for the three and nine months ended September 30, 2014 and 2013. The majority of the 2014 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 4.80%. The majority of the 2014 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.59% for funded plans and a discount rate of 4.90% for all plans. Certain of the other postretirement benefit plans were remeasured as of April 30, 2014 using an expected long-term rate of return on plan assets of 6.59% and a discount rate of 4.30%. Costs for the three and nine months ended September 30, 2014 reflect the impact of this remeasurement. On July 14, 2014 Exelon became the sponsor of the pension and other postretirement plans formerly sponsored by CENG. The components of cost for the CENG plans are included in the table below for the period from April 1, 2014 to September 30, 2014 and reflect the valuation performed on April 1, 2014. The 2014 pension benefit cost for these plans is calculated using an expected long-term rate of return on plan assets of 7.75% and discount rates ranging from 3.60% - 4.30%. The 2014 other postretirement benefit cost is calculated using a discount rate of 4.55%. A portion of the net periodic benefit cost is capitalized within the Consolidated Balance Sheets.

	Pension Benefits Three Months Ended September 30,		Other Postretirement Benefits Three Months Ended September 30,	
	2014[(a)]	2013[(a)]	2014[(a)]	2013[(a)]
Service cost	$ 74	$ 79	$ 27	$ 41
Interest cost	189	163	42	48
Expected return on assets	(251)	(253)	(39)	(33)
Amortization of:				
Prior service cost (benefit)	3	3	(44)	(4)
Actuarial loss	106	140	15	20
Settlement charges	—	9	—	—
Net periodic benefit cost	$ 121	$ 141	$ 1	$ 72

	Pension Benefits Nine Months Ended September 30,		Other Postretirement Benefits Nine Months Ended September 30,	
	2014[(b)]	2013[(b)]	2014[(b)]	2013[(b)]
Service cost	$ 218	$ 238	$ 90	$ 122
Interest cost	561	488	144	145
Expected return on assets	(743)	(761)	(115)	(99)
Amortization of:				
Prior service cost (benefit)	10	10	(79)	(14)
Actuarial loss	316	421	35	62
Settlement charges	—	9	—	—
Net periodic benefit cost	$ 362	$ 405	$ 75	$ 216

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

(a) For the three months ended September 30, 2014, the cost for pension benefits and other postretirement benefits related to CENG were $2 million and $3 million, respectively. CENG is not included in the 2013 amounts.
(b) For the period April 1, 2014 to September 30, 2014, the cost for pension benefits and other postretirement benefits related to CENG were $5 million and $6 million, respectively. CENG is not included in the 2013 amounts.

The amounts below represent Generation's, ComEd's, PECO's, BGE's and BSC's allocated portion of the pension and postretirement benefit plan costs, which were included in Capital expenditures and Operating and maintenance expense during the three and nine months ended September 30, 2014 and 2013.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Pension and Other Postretirement Benefit Costs	**2014**	**2013**	**2014**	**2013**
Generation[(a)]	$ 54	$ 87	$ 193	$ 259
ComEd	33	77	129	231
PECO	7	11	28	32
BGE	17	14	50	41
BSC[(b)]	11	24	37	58

(a) For the three months ended September 30, 2014, the cost for pension benefits and other postretirement benefits related to CENG were $2 million and $3 million, respectively. For the period April 1, 2014 to September 30, 2014, the cost for pension benefits and other postretirement benefits related to CENG were $5 million and $6 million, respectively. CENG is not included in the 2013 amounts.
(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO or BGE amounts above.

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. Exelon expects to make qualified pension plan contributions of $308 million to its qualified pension plans in 2014, of which Generation, ComEd, PECO and BGE will contribute $160 million, $119 million, $11 million and $0 million, respectively. Exelon's and Generation's expected qualified pension plan contributions above include $53 million and $51 million, respectively, related to the CENG plans for the period April 1, 2014 to December 31, 2014, of which $43 million will be funded by CENG as agreed to in the EMA. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded. Exelon expects to make non-qualified pension plan benefit payments of $18 million in 2014, of which Generation, ComEd, PECO and BGE will make payments of $9 million, $1 million, $0 million and $1 million, respectively. Exelon's and Generation's expected non-qualified pension plan benefit payments above include $3 million related to the CENG plans for the period April 1, to December 31, 2014.

Unlike qualified pension plans, other postretirement benefit plans are not subject to statutory minimum contribution requirements and certain plans are not funded. Exelon's management has historically considered several factors in determining the level of contributions to its funded other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued rate recovery). Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans and reflecting the impact of recent plan design changes, of approximately $290 million in 2014, of which Generation, ComEd, PECO and BGE expect to contribute $128 million, $121 million, $4 million and $18 million, respectively. Exelon's and Generation's expected other postretirement benefit plan payments above include $5 million related to the CENG plans for the period April 1, 2014 to December 31, 2014.

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

Plan Assets

Investment Strategy. On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

Exelon has developed and implemented a liability hedging investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon may increase or decrease the liability hedging portfolio as the funded status of its plans changes. The overall objective is to achieve long term investment returns that, taking into account projected contributions and liquidity requirements, provide sufficient assets to meet current and future benefit obligations while maintaining acceptable levels of funding status volatility. Trust assets for Exelon's other postretirement plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

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 income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the three and nine months ended September 30, 2014 and 2013:

Savings Plan Matching Contributions	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Exelon[(a)]	$ 34	$ 18	$ 82	$ 61
Generation[(a)]	17	8	41	29
ComEd	8	6	20	16
PECO	2	2	6	6
BGE	3	1	7	5
BSC[(b)]	4	1	8	5

(a) Includes $1 million related to CENG for the three months ended September 30, 2014 and for the period from April 1, 2014 to September, 30 2014. CENG is not included in the 2013 amounts.
(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO or BGE amounts above.

14. Severance (Exelon, Generation, ComEd, PECO and BGE)

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.

CENG Integration-Related Severance

In connection with the Master Agreement, Generation and CENG recorded a severance accrual in the fourth quarter of 2013 for the anticipated employee position reductions as a result of the integration. The majority of these positions are corporate and support positions at CENG. On April 1, 2014, the date the NOSA was executed, Generation consolidated the CENG severance liability pursuant to the Master Agreement. Generation adjusts its accrual each quarter to reflect its best estimate of remaining severance costs. The estimated amount of severance payments associated with this plan is expected to be approximately $27 million. As of September 30, 2014, management recorded its best estimate of severance benefits, which could be adjusted through the completion of the integration process if additional employee position reductions are identified or if employees resign prior to their agreed upon service termination date. Estimated costs to be incurred after September 30, 2014 are not material.

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

Amounts included in the table below represent the severance liability recorded by Exelon and Generation related to the CENG integration:

Nine Months Ended September 30, 2014 Severance Liability	Exelon and Generation
Balance at December 31, 2013	$ 2
Integration of CENG[(a)]	19
Severance charges	2
Payments	(7)
Balance at September 30, 2014	$ 16

(a) Includes the fair value of the CENG integration-related obligation as of April 1, 2014, the date of consolidation. Note this does not include $4 million of severance charges that were paid out prior to consolidation. See Note 6 — Investment in Constellation Energy Nuclear Group, LLC for additional information.

Cash payments under the severance plan began by CENG in the first quarter of 2014. Substantially all cash payments under the plan are expected to be made by the end of 2015.

Constellation Merger-Related Severance

Upon closing the merger with Constellation, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. The majority of these positions are corporate and Generation support positions. Since then, Exelon has identified specific employees to be severed pursuant to the merger-related staffing and selection process as well as employees that were previously identified for severance but have since accepted another position within Exelon and are no longer receiving a severance benefit.

The amount of severance expense associated with the post-merger integration recognized for the three and nine months ended September 30, 2014 and 2013 is not material. Estimated costs to be incurred after September 30, 2014 are not material.

Amounts included in the table below represent the severance liability recorded by Exelon, Generation, ComEd, PECO and BGE for employees of those Registrants and exclude amounts billed through intercompany allocations:

Nine Months Ended September 30, 2014 Severance Liability	Exelon	Generation	ComEd	PECO	BGE
Balance at December 31, 2013	$ 53	$ 10	$ —	$ —	$ 6
Payments	(36)	(5)	—	—	(4)
Balance at September 30, 2014	$ 17	$ 5	$ —	$ —	$ 2

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

Substantially all cash payments under the plan are expected to be made by the end of 2016.

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, which are not directly related to the merger with Constellation or with the integration of CENG. These benefits are accrued for when the benefits are considered probable and can be reasonably estimated.

For the three and nine months ended September 30, 2014 and 2013, the Registrants recorded the following severance costs associated with these ongoing severance benefits within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income:

Three Months Ended	Exelon	Generation	ComEd	PECO	BGE
September 30, 2014	$ (2)	$ (2)	$ —	$ —	$ —
September 30, 2013	$ 12	$ 11	$ 1	$ —	$ —

Nine Months Ended	Exelon	Generation	ComEd	PECO	BGE
September 30, 2014	$ 4	$ 3	$ 1	$ —	$ —
September 30, 2013	$ 14	$ 12	$ 2	$ —	$ —

The severance liability balances associated with these ongoing severance benefits as of September 30, 2014 and December 31, 2013 are not material.

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

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

The following tables present changes in accumulated other comprehensive income (loss) (AOCI) by component for the nine months ended September 30, 2014 and 2013:

Nine Months Ended September 30, 2014	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	$ 120	$ 2	$ (2,260)	$ (10)	$ 108	$(2,040)
OCI before reclassifications	(14)	(2)	240	(6)	11	229
Amounts reclassified from AOCI[b]	(78)	—	91	—	(119)	(106)
Net current-period OCI	(92)	(2)	331	(6)	(108)	123
Ending balance	$ 28	$ —	$ (1,929)	$ (16)	$ —	$(1,917)
Generation[a]						
Beginning balance	$ 114	$ 2	$ —	$ (10)	$ 108	$ 214
OCI before reclassifications	(8)	(3)	—	(6)	11	(6)
Amounts reclassified from AOCI[b]	(78)	—	—	—	(119)	(197)
Net current-period OCI	(86)	(3)	—	(6)	(108)	(203)
Ending balance	$ 28	$ (1)	$ —	$ (16)	$ —	$ 11
PECO[a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI[b]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in accumulated other comprehensive income.
(b) See tables following changes in accumulated other comprehensive income tables for details about these reclassifications.

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

Nine Months Ended September 30, 2013	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	$ 368	$ —	$ (3,137)	$ —	$ 2	$(2,767)
OCI before reclassifications	25	(1)	73	(5)	46	138
Amounts reclassified from AOCI[b]	(194)	—	157	—	5	(32)
Net current-period OCI	(169)	(1)	230	(5)	51	106
Ending balance	$ 199	$ (1)	$ (2,907)	$ (5)	$ 53	$(2,661)
Generation[a]						
Beginning balance	$ 512	$ —	$ —	$ —	$ 1	$ 513
OCI before reclassifications	12	(1)	—	(5)	47	53
Amounts reclassified from AOCI[b]	(328)	—	—	—	5	(323)
Net current-period OCI	(316)	(1)	—	(5)	52	(270)
Ending balance	$ 196	$ (1)	$ —	$ (5)	$ 53	$ 243
PECO[a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI[b]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in accumulated other comprehensive income.
(b) See tables following changes in accumulated other comprehensive income tables for details about these reclassifications.

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

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ComEd, PECO, and BGE did not have any reclassifications out of AOCI to net income during the three and nine months ended September 30, 2014 and 2013. The following tables present amounts reclassified out of AOCI to Net Income for Exelon and Generation during the three and nine months ended September 30, 2014 and 2013.

Three Months Ended September 30, 2014

Details about AOCI components	Items reclassified out of AOCI[a] Exelon	Generation	Affected line item in the statement where Net Income is presented
Gains on cash flow hedges			
Energy related hedges	$ 28	$ 28	Operating revenues
	28	28	Total before tax
	(12)	(12)	Tax (expense)
	$ 16	$ 16	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs	$ 19	$ —	(b)
Actuarial losses	(61)	—	(b)
	(42)	—	Total before tax
	16	—	Tax benefit
	$ (26)	$ —	Net of tax
Equity investments			
Sale of equity method investment	$ 5	$ 5	Other, net
	5	5	Total before tax
	(2)	(2)	Tax (expense)
	$ 3	$ 3	Net of tax
Total Reclassifications for the period	$ (7)	$ 19	Net of Tax

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

Nine Months Ended September 30, 2014

Details about AOCI components	Items reclassified out of AOCI[a] Exelon	Items reclassified out of AOCI[a] Generation	Affected line item in the statement where Net Income is presented
Gains on cash flow hedges			
Energy related hedges	$ 130	$ 130	Operating revenues
	130	130	Total before tax
	(52)	(52)	Tax (expense)
	$ 78	$ 78	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs	$ 29	$ —	(b)
Actuarial losses	(178)	—	(b)
	(149)	—	Total before tax
	58	—	Tax benefit
	$ (91)	$ —	Net of tax
Equity investments			
Sale of equity method investment	$ 5	$ 5	Other, net
Reversal of CENG equity method AOCI	193	193	Gain on consolidation of CENG
	198	198	Total before tax
	(79)	(79)	Tax (expense)
	$ 119	$ 119	Net of tax
Total reclassifications for the period	$ 106	$ 197	Net of Tax

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

Three Months Ended September 30, 2013

Details about AOCI components	Items reclassified out of AOCI[(a)] Exelon	Items reclassified out of AOCI[(a)] Generation	Affected line item in the statement where Net Income is presented
Gains on cash flow hedges			
Energy related hedges	$ 84	$ 84	Operating revenues
Other cash flow hedges	(1)	(1)	Interest expense
	83	83	Total before tax
	(35)	(33)	Tax (expense)
	$ 48	$ 50	Net of tax
Amortization of pension and other postretirement benefit plan items			
Actuarial losses	$ (92)	$ —	(b)
Deferred compensation unit plan	(1)	—	(c)
	(93)	—	Total before tax
	37	—	Tax benefit
	$ (56)	$ —	Net of tax
Equity investments			
Capital Activity	$ —	$ —	Equity in losses of unconsolidated affiliates
	—	—	Total before tax
	—	—	Tax benefit
	$ —	$ —	Net of tax
Total Reclassifications for the period	$ (8)	$ 50	Net of Tax

Nine Months Ended September 30, 2013

Details about AOCI components	Items reclassified out of AOCI[(a)] Exelon	Items reclassified out of AOCI[(a)] Generation	Affected line item in the statement where Net Income is presented
Gains on cash flow hedges			
Energy related hedges	$ 324	$ 543	Operating revenues
Other cash flow hedges	(2)	—	Interest (expense) or benefit
	322	543	Total before tax
	(128)	(215)	Tax (expense)
	$ 194	$ 328	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs	$ (1)	$ —	(b)
Actuarial losses	(257)	—	(b)
Deferred compensation unit plan	(1)	—	(c)
	(259)	—	Total before tax
	102	—	Tax benefit
	$ (157)	$ —	Net of tax
Equity investments			
Capital Activity	$ (8)	$ (8)	Equity in losses of unconsolidated affiliates
	(8)	(8)	Total before tax
	3	3	Tax benefit
	$ (5)	$ (5)	Net of tax
Total Reclassifications for the period	$ 32	$ 323	Net of Tax

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

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in net income.
(b) This accumulated other comprehensive income component is included in the computation of net periodic pension and OPEB cost (see Note 13 — Retirement Benefits for additional details).
(c) Amortization of deferred compensation unit is allocated to capital and operating and maintenance expense.

The following table presents income tax expense (benefit) allocated to each component of other comprehensive income (loss) during the three and nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Exelon				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	$ 8	$ —	11	$ —
Actuarial gain (loss) reclassified to periodic cost	(24)	33	(69)	97
Pension and non-pension postretirement benefit plans valuation adjustment	5	(6)	(153)	44
Change in unrealized gain (loss) on cash flow hedges	15	(35)	62	(109)
Change in unrealized income on equity investments	3	9	73	32
Deferred compensation unit valuation adjustment	—	—	—	6
Change in unrealized loss on marketable securities	1	—	(1)	—
Total	$ 8	$ 1	$ (77)	$ 70
Generation				
Change in unrealized gain (loss) on cash flow hedges	$ 13	$ (36)	$ 57	$ (209)
Change in unrealized income on equity investments	3	9	73	32
Change in marketable securities	1	—	(1)	—
Total	$ 17	$ (27)	$ 129	$ (177)

16. Common Stock (Exelon, Generation, ComEd, PECO and BGE)

Equity Securities Offering

In June 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of $35 per share. In connection with such offering, Exelon entered into forward sale agreements requiring Exelon to, at its election, prior to October 29, 2015; i) physically settle the transaction through the issuance of 57.5 million shares of its common stock in exchange for net proceeds at the forward price specified in the agreements of between approximately $1.85 billion and $1.95 billion, after consideration of underwriters discount of approximately $60 million and subject to certain adjustments as provided in the forward sales agreement, or ii) net settle the transaction either through the payment of cash or shares of its common stock based on the then current market value of the shares minus the value of the shares at the forward price, net of the underwriters discount and the daily accretion rate. No amounts have or will be recorded in Exelon's consolidated financial statements with respect to the equity offering until settlement of the forward sale agreements occurs. If Exelon elected to net share settle the contract as of September 30, 2014, Exelon would not have been required to issue shares, as the average share price during the quarter was below the forward price of $33.58 per share. If Exelon elects to cash settle the contract, the transaction costs will be recorded as a charge to earnings in the period in which it becomes probable that Exelon will cash settle. Otherwise, all transaction costs will be reflected as a reduction to the value of the common stock issued in Exelon's Consolidated Balance Sheet. The net proceeds received upon settlement are expected to be used to finance a portion of the acquisition of PHI and for general corporate purposes. Until settlement, earnings per share dilution resulting from the forward sales agreement, if any, will be determined under the treasury stock method.

Concurrent with the forward equity transaction, Exelon also issued $1.15 billion of junior subordinated notes in the form of 23 million equity units. See Note 10 — Debt and Credit Agreements for further information on the equity units.

17. Earnings Per Share and Equity (Exelon)

Earnings per Share (Exelon)

Diluted earnings per share is calculated by dividing Net income attributable to common shareholders by the weighted average number of shares of common stock outstanding adjusted to include the potentially dilutive effect of stock options, performance share awards and restricted stock outstanding under Exelon's LTIPs. 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 (in millions) used in calculating diluted earnings per share:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net income attributable to common shareholders	$ 993	$ 738	$ 1,604	$ 1,224
Average common shares outstanding — basic	861	857	860	856
Potentially dilutive effect of stock options, performance share awards and restricted stock	2	3	3	4
Average common shares outstanding — diluted	863	860	863	860

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 16 million for the three and nine months ended September 30, 2014 and 20 million for the three and nine months ended September 30, 2013. 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 approximately 2 million for the three months ended September 30, 2014 and 1 million since issuance. The number of forward units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 2 million for the three months ended September 30, 2014 and less than 1 million since issuance.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion as of September 30, 2014. In 2008, Exelon management decided to defer indefinitely any share repurchases.

Preferred Securities Redemption (Exelon and PECO)

On March 25, 2013, PECO announced that it issued a notice of redemption for all of its outstanding preferred securities with a redemption date of May 1, 2013. PECO had $87 million of cumulative preferred securities that were redeemable at its option at any time for the redemption price established when each series of securities were issued. The redemption premium of $6 million is treated as a reduction to Net income to arrive at Net income attributable to common shareholders utilized in the calculation of the earnings per share for Exelon. As a result of the redemption, PECO is now indirectly, wholly-owned by Exelon.

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

18. Commitments and Contingencies (Exelon, Generation, ComEd, PECO and BGE)

The following is an update to the current status of commitments and contingencies set forth in Note 22 of the Exelon 2013 Form 10-K.

Commitments

Energy Commitments

As of September 30, 2014, Generation's commitments relating to its purchases from unaffiliated utilities and others of energy, capacity, transmission rights and RECs, are as indicated in the following table:

	Net Capacity Purchases[(a)]	REC Purchases[(b)]	Transmission Rights Purchases[(c)]	Total
2014	$ 91	$ 7	$ 6	$ 104
2015	396	162	20	578
2016	269	166	15	450
2017	208	80	15	303
2018	98	15	16	129
Thereafter	389	4	51	444
Total	$ 1,451	$ 434	$ 123	$2,008

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at September 30, 2014, net of fixed capacity payments expected to be received ("capacity offsets") by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. As of September 30, 2014, capacity offsets were $23 million, $132, million $133 million, $136, million, $137 million, and $729 million for years 2014, 2015, 2016, 2017, 2018, and thereafter, respectively. Expected payments include certain fixed capacity charges which may be reduced based on plant availability.
(b) The table excludes renewable energy purchases that are contingent in nature.
(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

ComEd's, PECO's and BGE's electric supply procurement, curtailment services, REC and AEC purchase commitments, as applicable, as of September 30, 2014 are as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
ComEd							
Electric supply procurement[(a)]	$ 731	$111	$329	$151	$140	$—	$ —
Renewable energy and RECs[(b)]	1,538	22	73	76	77	78	1,212
PECO							
Electric supply procurement[(c)]	498	193	305	—	—	—	—
AECs[(d)]	13	1	2	2	2	2	4
BGE							
Electric supply procurement[(e)]	1,055	198	621	236	—	—	—
Curtailment services[(f)]	125	10	40	34	29	12	—

(a) ComEd entered into various contracts for the procurement of electricity that started to expire in 2012, and will continue to expire through 2017. ComEd is permitted to recover its electric supply procurement costs from retail customers with no mark-up. As of September 30, 2014, ComEd has completed the ICC-approved procurement process for a portion of its energy requirements through the periods ending May 31, 2015, 2016 and 2017.

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

(b) Primarily related to ComEd 20-year contracts for renewable energy and RECs that began in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms.

(c) PECO entered into various contracts for the procurement of electric supply to serve its default service customers that expire between 2014 and 2015. PECO is permitted to recover its electric supply procurement costs from default service customers with no mark-up in accordance with its PAPUC-approved DSP Programs. See Note 5 — Regulatory Matters for additional information.

(d) PECO is subject to requirements related to the use of alternative energy resources established by the AEPS Act. See Note 5 — Regulatory Matters for additional information.

(e) BGE entered into various contracts for the procurement of electricity that expire between 2014 through 2016. The cost of power under these contracts is recoverable under MDPSC approved fuel clauses. See Note 5 — Regulatory Matters for additional information.

(f) BGE has entered into various contracts with curtailment services providers related to transactions in PJM's capacity market. See Note 5 —Regulatory Matters for additional information.

Fuel Purchase Obligations

In addition to the energy commitments described above, Generation has commitments to purchase fuel supplies for nuclear and fossil generation. Beginning with the second quarter of 2014, all of CENG's nuclear fuel commitments are disclosed within the Generation line below, since CENG is now fully consolidated by Generation. PECO and BGE have commitments to purchase natural gas related to transportation, storage capacity and services to serve customers in their gas distribution service territory. As of September 30, 2014, these net commitments were as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Generation	$9,636	$351	$1,512	$1,226	$1,271	$1,003	$ 4,273
PECO	387	57	120	94	35	15	66
BGE	624	40	115	81	64	53	271

Other Purchase Obligations

The Registrants' other purchase obligations as of September 30, 2014, which primarily represent commitments for services, materials and information technology, are as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Exelon	$917	$103	$324	$180	$151	$36	$ 123
Generation(a)(b)	493	80	182	57	43	30	101
ComEd(c)	92	13	38	16	5	5	15
PECO(c)	29	7	11	2	1	1	7
BGE(c)	302	2	93	105	102	—	—

(a) Purchase obligations do not include commitments related to construction contracts. See Construction Commitments section below for additional information.
(b) Purchase obligations include commitments related to assets-held-for-sale. See Note 4 — Mergers, Acquisitions and Dispositions for additional information.
(c) Purchase obligations include commitments related to smart meter installation. See Note 5 — Regulatory Matters for additional information.

Construction Commitments

Generation's ongoing investments in renewables development, new natural gas and biomass generation construction illustrates Generation's growth strategy to provide for diversification opportunities while leveraging its expertise and strengths.

Generation completed the construction of the Antelope Valley solar PV facility in Los Angeles County, California, which became fully operational in the first half of 2014. Generation has no further remaining construction commitments for the project.

On July 3, 2013, Generation executed a Turbine Supply Agreement to expand its Beebe wind project in Michigan. The estimated remaining commitment under the contract is $6 million and achievement of commercial operations is expected in the fourth quarter of 2014.

On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland generation site with 120 MW of new natural gas-fired generation. The estimated remaining commitment under the contract is $75 million and achievement of commercial operations is expected in 2015. This project will satisfy a portion of Exelon's commitment to Maryland. See Constellation Merger Commitment below for further information.

On December 27, 2013, Generation executed a Turbine Supply Agreement for construction of the 40 MW Fourmile Wind project in western Maryland. The estimated remaining commitment under the contract is $7 million and achievement of commercial operations is expected in the fourth quarter 2014. This project will satisfy a portion of Exelon's 125 MW Tier I land-based renewables commitment made to Maryland. See Constellation Merger Commitment below for further information.

During the third quarter of 2014, Generation executed equipment procurement contracts associated with the construction of new combined-cycle gas turbine units in Texas. The estimated commitment under these contracts is $334 million and achievement of commercial operations is expected in 2017.

Refer to Note 3 — Regulatory Matters of the Exelon 2013 Form 10-K for information on investment programs associated with regulatory mandates, such as ComEd's Infrastructure Investment Plan under EIMA, PECO's Smart Meter Procurement and Installation Plan and BGE's comprehensive smart grid initiative.

Constellation Merger Commitments

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. On March 20, 2013, Generation signed a 20 year lease agreement that was contingent upon the developer obtaining all required approvals, permits and financing for the construction of a building in Baltimore, Maryland. The operating lease became effective during the second quarter of 2014 when these outstanding contingencies were met by the developer. Generation's total commitments under the lease agreement are $0 related to 2014 and 2015, and $10 million, $12 million, $13 million, and $290 million related to 2016, 2017, 2018, and 2019 and thereafter.

The direct investment commitment also includes $600 million to $650 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 over 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 expect that the majority of these commitments will be satisfied by building or acquiring generating assets and, therefore, will be primarily capital in nature and recognized as incurred. However, during the third quarter of 2014 the conditions associated with one of the generation development commitments have changed such that Exelon and Generation now believe that the most likely outcome will involve making subsidy payments and/or liquidated damages payments rather than constructing the specified generating plant. As a result, Exelon and Generation have recorded a pre-tax $44 million loss contingency related to this generation development commitment which is included in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. While this $44 million loss contingency represents Generation's best estimate of the future obligation, it is reasonably possible that Exelon and Generation could ultimately be required to make cumulative subsidy payments of up to a maximum of approximately $105 million over a 20-year period dependent on actual generating output from a successfully constructed generating plant. See Note 4 — Mergers and Acquisitions of the Exelon 2013 Form 10-K for additional information regarding the Constellation merger commitments.

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

Equity Investment Commitments

As part of Generation's recent investments in technology development, Generation has entered into equity purchase agreements which include commitments to purchase additional equity through incremental payments. The additional equity is provided by the agreements to fund the anticipated needs of the planned operations of the associated companies. The commitment includes approximately $20 million of in-kind services. As of September 30, 2014, Generation's estimated commitment relating to its equity purchase agreements, including the in-kind services contributions, is anticipated to be as follows:

	Total
2014	$ 27
2015	86
2016	34
2017	20
2018	15
Total	$182

Contingencies

Commercial Commitments

The Registrants' commercial commitments as of September 30, 2014, representing commitments potentially triggered by future events were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Letters of credit (non-debt)[a]	$1,021	$ 973	$ 20	$ 22	$ 1
Guarantees	4,902[b]	1,604[c]	206[d]	181[e]	259[f]
Nuclear insurance premiums[g]	3,559	3,559	—	—	—
Underwriters discount[h]	60	—	—	—	—
Total commercial commitments	$9,542	$ 6,136	$ 226	$203	$260

(a) Non-debt letters of credit maintained to provide credit support for certain transactions as requested by third parties.

(b) Primarily reflects parental guarantees issued on behalf of Generation to allow the flexibility needed to conduct business with counterparties without having to post other forms of collateral. Also reflects guarantees issued to ensure performance under specific contracts, preferred securities of financing trusts, property leases, indemnifications, NRC minimum funding assurance requirements and miscellaneous guarantees. The estimated net exposure for obligations under commercial transactions covered by these guarantees was $467 million at September 30, 2014, which represents the total amount Exelon could be required to fund based on September 30, 2014 market prices.
(c) Primarily reflects guarantees issued to ensure performance under energy marketing and other specific contracts. The estimated net exposure for obligations under commercial transactions covered by these guarantees was $205 million at September 30, 2014, which represents the total amount Generation could be required to fund based on September 30, 2014 market prices.
(d) Primarily reflects full and unconditional guarantees of $200 million Trust Preferred Securities of ComEd Financing III, which is a 100% owned finance subsidiary of ComEd.
(e) Primarily reflects full and unconditional guarantees of $178 million Trust Preferred Securities of PECO Trust III and IV, which are 100% owned finance subsidiaries of PECO.
(f) Primarily reflects full and unconditional guarantees of $250 million Trust Preferred Securities of BGE Capital Trust II, which is a 100% owned finance subsidiary of BGE.
(g) Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site, including CENG sites, under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.
(h) Represents the underwriters discount for Exelon's forward equity transaction. See Note 16 — Common Stock of the Combined Notes to Consolidated Financial Statements for further details of the equity securities offering.

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 reduced 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 September 30, 2014, the current liability limit per incident was $13.6 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. An inflation adjustment must be made at least once every 5 years and the last inflation adjustment was made effective September 10, 2013. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. As of September 30, 2014, the amount of nuclear energy liability insurance purchased is $375 million for each operating site. Additionally, the Price-Anderson Act requires a second layer of protection through the mandatory participation in a retrospective rating plan for power reactors (currently 104 reactors) resulting in an additional $13.2 billion in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Under the Price-Anderson Act, the maximum assessment in the event of an incident for each nuclear operator, per reactor, per incident (including a 5% surcharge), is $127.3 million, payable at no more than $19 million per reactor per incident per year. Exelon's maximum liability per incident is approximately $2.7 billion, including CENG's related liability.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.6 billion limit for a single incident.

Generation is also required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member. Premiums paid to NEIL by its members are subject to assessment for adverse loss experience (the retrospective premium obligation). The maximum combined retrospective premium amount that Generation could be required to pay due to participation in the Price-Anderson Act retrospective rating plan for power reactors and the NEIL retrospective premium obligation is $3.6 billion, including CENG's obligation, which is included above in the Commercial Commitments table. See the Nuclear Insurance section within Note 22 — Commitments and Contingencies of the Exelon 2013 Form 10-K for additional details on Generation's nuclear insurance premiums.

As part of the execution of the NOSA on April 1, 2014, Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this indemnity. See Note 6 — Investment in Constellation Energy Nuclear Group, LLC for additional information on Generation's operations relating to CENG.

Spent Nuclear Fuel Obligation (Exelon and Generation)

Under the NWPA, the DOE is responsible for the development of a geologic repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, Generation is a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from Generation's nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation pays the DOE one mill ($0.001) per kWh of net nuclear generation for the cost of SNF disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance will be delayed significantly. On November 19, 2013, the D.C. Circuit Court ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. On January 3, 2014, the DOE filed a petition for rehearing which was denied by the D.C. Circuit Court on March 18, 2014. Also, on January 3, 2014, the DOE submitted a proposal to Congress to reduce the current SNF disposal fee to zero. On May 9, 2014, the DOE notified Generation that the SNF disposal fee will remain in effect through May 15, 2014, after which time the fee will be set to zero. For the nine months ended September 30, 2014, and for the year ended December 31, 2013, Generation incurred expense of $49 million and $136 million respectively, in SNF disposal fees, recorded in Purchased power and fuel expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income, including Exelon's share of Salem and net of co-owner reimbursements (not including such fees incurred by CENG). Until such time as a new fee structure is in effect, Exelon and Generation will not accrue any further costs related to SNF disposal fees.

Indemnifications Related to Sale of Sithe (Exelon and Generation)

On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation's sale of its investment in Sithe. Specifically, subsidiaries of Generation consummated the acquisition of Reservoir Capital Group's 50% interest in Sithe and subsequently sold 100% of Sithe to Dynegy, Inc. (Dynegy).

The estimated maximum possible exposure to Exelon related to the guarantees provided as part of the sales transaction to Dynegy was approximately $200 million at December 31, 2013. The guarantee expired January 31, 2014. Generation was not required to make payments under the guarantee, and, therefore, has no further obligation related to this guarantee.

Repurchase of Land Related to Master Agreement Closing (Exelon and Generation)

As a result of the closing of the transactions contemplated by the Master Agreement, EDF has the option to sell back to CENG the land adjacent to the Calvert Cliffs site, together with the rights associated with the land, at its fair market value. The option is exercisable for a period of five years, from April 1, 2014.

Environmental Issues

General. The Registrants' operations have in the past, and may in the future, require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

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

- ComEd has identified 42 sites, 17 of which the remediation has been completed and approved by the Illinois EPA or the U.S. EPA and 25 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2019.
- PECO has identified 26 sites, 16 of which have been remediated in accordance with applicable PA DEP regulatory requirements. The remaining 10 sites are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2021.
- BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor's acquisition. Two gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. One gas purification site is in the initial stages of investigation at the direction of the MDE. At this time, BGE is unable to estimate the results of this investigation.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. BGE is authorized to recover, and is currently recovering, environmental costs for the remediation of former MGP facility sites from customers; however, while BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. ComEd, PECO and BGE have recorded regulatory assets for the recovery of these costs. See Note 5 — Regulatory Matters for additional information regarding the associated regulatory assets.

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

As of September 30, 2014 and December 31, 2013, the Registrants had accrued the following undiscounted amounts for environmental liabilities in other current liabilities and other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

September 30, 2014	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 342	$ 280
Generation	55	—
ComEd	241	237
PECO	45	43
BGE	1	—

December 31, 2013	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 338	$ 273
Generation	56	—
ComEd	234	229
PECO	47	44
BGE	1	—

The historical nature of the MGP sites and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs based on probabilistic and deterministic modeling using all available information at the time of each study and the remediation standards currently required by the applicable state environmental agency. Prior to completion of any significant clean up, each site remediation plan is approved by the appropriate state environmental agency.

During the third quarter of 2014, ComEd and PECO completed an annual study of their future estimated MGP remediation requirements. The results of these studies indicated that additional remediation would be required at certain sites. Accordingly ComEd and PECO increased their environmental liabilities and related regulatory assets by $26 million and $4 million, respectively, primarily reflecting refined assumptions regarding clean-up techniques and scopes based on additional experience and analysis as site clean-up and investigation activities progress.

BGE has established a reserve for the active sites that is not material. Given that the former gas purification site is in the early stages of investigation and the extent of contamination is not currently known, BGE is unable to estimate actual remediation costs, which may be material to BGE's results of operations, cash flows, and financial position.

The Registrants cannot reasonably estimate whether they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

Water Quality

Section 316(b) of the Clean Water Act. Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's and CENG's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by changes to the existing regulations. For Generation, those facilities are Clinton, Dresden, Eddystone, Fairless Hills, Gould Street, Handley, Mountain Creek, Mystic 7, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill. For CENG, those facilities are Calvert Cliffs, Nine Mile Point Unit 1 and R.E. Ginna.

On October 14, 2014, the U.S. EPA's final Section 316(b) rule became effective. The rule requires that a series of studies and analyses be performed to determine the best technology available, followed by an implementation period. The timing of the various requirements for each facility is related to the status of its current NPDES permit and the subsequent renewal period. There is no fixed compliance schedule, as this is left to the discretion of the state permitting director.

The rule does not require closed-cycle cooling (e.g., cooling towers) as the best technology available to address impingement and entrainment of aquatic life at a facility's cooling water intake structure. The rule provides the state permitting director with significant discretion to determine the best technology available to limit entrainment (drawing aquatic life into the plants cooling system) mortality, including application of a cost-benefit test and the consideration of a number of site-specific factors. After consideration of these factors, the state permitting agency may require closed cycle cooling, an alternate technology, or determine that the current technology is the best available. The rule also provides a number of flexible compliance options to reduce impingement (trapping aquatic life on screens) mortality, which likely will be accomplished by the installation of screens or other technology at the intake. A number of concerns raised by the electric generation industry about the proposed rule were resolved favorably in the final rule.

New York Facilities. In July 2011, the New York Department of Environmental Conservation (DEC) issued a policy regarding the best available technology for cooling water intake structures. Through its policy, the DEC established closed-cycle cooling or its equivalent as the performance goal for all existing facilities, but also provided that the DEC will select a feasible technology whose costs are not wholly disproportionate to the environmental benefits to be gained and allows for a site-specific determination where the entrainment performance goal cannot be achieved. Each of CENG's New York facilities has filed for its SPDES permit renewal in 2014 and the renewal applications are not yet effective.

Salem and Other Power Generation Facilities. In June 2001, the NJDEP issued a renewed NPDES permit for Salem, allowing for the continued operation of Salem with its existing cooling water system. NJDEP advised PSEG, in July 2004, that it strongly recommended reducing cooling water intake flow commensurate with closed-cycle cooling as a compliance option for Salem. PSEG submitted an application for a renewal of the permit on February 1, 2006. In the permit renewal application, PSEG analyzed closed-cycle cooling and other options and demonstrated that the continuation of the Estuary Enhancement Program, an extensive environmental restoration program at Salem, is the best technology to meet the Section 316(b) requirements. PSEG continues to operate Salem under the approved June 2001 NPDES permit while the NPDES permit renewal application is being reviewed. If the final permit or Section 316(b) regulations ultimately requires the retrofitting of Salem's cooling water intake structure to reduce cooling water intake flow commensurate with closed-cycle cooling, Exelon's and Generation's share of the total cost of the retrofit and any resulting interim replacement power would likely be in excess of $430 million, based on a 2006 estimate, and would result in increased depreciation expense related to the retrofit investment. However, it is unknown at this time whether implementation of the final EPA rule will result in a requirement to install closed cycle cooling at Salem.

Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, Generation cannot estimate the effect that compliance with the rule will have on the operation of its and CENG's generating facilities and its future results of operations, cash flows and financial position. Should a state permitting director determine that a facility must install cooling towers to comply with the rule, that facility's economic viability would be called into question. However, the likely impact of the rule has been significantly decreased since the final rule does not mandate cooling towers as a national standard, and the state permitting director is required to apply a cost-benefit test and can take into consideration site-specific factors.

Groundwater Contamination. In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third-party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a $1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. As of September 30, 2014, and December 31, 2013, Generation's remaining groundwater contamination reserve was $14 million and $14 million respectively. In addition, a private party asserted claims relating to groundwater contamination. In February 2014, Generation settled these private party claims for an amount that was not material to the financial condition of Generation.

Air Quality

Cross State Air Pollution Rule (CSAPR). On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) vacated the CAIR, which had been promulgated by the U.S. EPA to reduce power plant emissions of SO2 and NOx. The D.C. Circuit Court later remanded the CAIR to the U.S. EPA, without invalidating the entire rulemaking, so that the U.S. EPA could correct CAIR in accordance with the D.C. Circuit Court's July 11, 2008 opinion. On July 7, 2011, the U.S. EPA published the final rule, known as the CSAPR. The CSAPR requires 28 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states.

Numerous entities challenged the CSAPR in the D.C. Circuit Court, and some requested a stay of the rule pending the Court's consideration of the matter on the merits. On December 30, 2011, the Court granted a stay of the CSAPR, and directed the U.S. EPA to continue the administration of CAIR in the interim. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA has exceeded its authority in certain material aspects of the CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. The Court's order was appealed to the U.S. Supreme Court, and on April 29, 2014, the U.S. Supreme Court reversed the D.C. Circuit Court decision and upheld CSAPR, and remanded the case to the D.C. Circuit Court to resolve the remaining implementation issues. On June 26, 2014, the U.S. EPA filed a motion with the D.C. Circuit Court seeking to have the stay of the CSAPR lifted, and proposed a three-year tolling of the effective dates under the rule so that the first phase of emission budgets would be implemented on January 1, 2015. The U.S. EPA believes that this would allow sufficient time to complete the remaining aspects of the rulemaking before the implementation of the more stringent second phase of emission budgets that, under the tolling proposal, would begin on January 1, 2017.

The CSAPR restricts entirely the use of pre-2012 allowances. Existing SO2 allowances under the ARP would remain available for use. As of September 30, 2014, Generation had $66 million of emission allowances carried at the lower of weighted average cost or market.

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

EPA Mercury and Air Toxics Standards (MATS). The MATS rule became final on April 16, 2012. The MATS rule reduces emissions of toxic air pollutants, and finalized the new source performance standards for fossil fuel-fired electric utility steam generating units (EGUs). The MATS rule requires coal-fired EGUs to achieve high removal rates of mercury, acid gases and other metals from air emissions. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that smaller, older, uncontrolled coal units will retire rather than make these investments. Coal units with existing controls that do not meet the required standards may need to upgrade existing controls or add new controls to comply. In addition, the new standards will require oil units to achieve high removal rates of metals. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies or retire the units. The MATS rule requires generating stations to meet the new standards three years after the rule takes effect, April 16, 2015, with specific guidelines for an additional one or two years in limited cases. Numerous entities challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. On April 15, 2014, the D.C Circuit Court issued an opinion upholding MATS in its entirety. On July 14, 2014, three petitions for certiorari were filed with the U.S. Supreme Court seeking review of the D.C. Circuit Court decision upholding MATS.

Exelon, along with the other co-owners of Conemaugh Generating Station, have improved the existing scrubbers and installed Selective Catalytic Reduction (SCR) controls at that station to meet the requirements of MATS.

In addition, as of September 30, 2014, Exelon had a $357 million net investment in coal-fired plants in Georgia subject to long-term leases extending through 2028 and 2030. While Exelon currently estimates the value of these plants at the end of the lease term will be in excess of the recorded residual lease values, after the impairments recorded in the second quarter of 2013 and 2014, final applications of the CSAPR and MATS regulations could negatively impact the end-of-lease term values of these assets, which could result in a future impairment loss that could be material. See Note 7 — Impairment of Long-Lived Assets for additional information.

National Ambient Air Quality Standards (NAAQS). The U.S. EPA previously announced that it would complete a review of all NAAQS by 2014. Oral argument in the litigation (*State of Miss. v. EPA*) of the final 2008 ozone standard occurred in the D.C. Circuit Court in November 2012 and a final Court decision was issued on July 23, 2013 with the 2008 primary ozone standard upheld, but the secondary standard remanded to EPA for reconsideration. On October 6, 2014, the Supreme Court declined to hear an industry petition for certiorari related to the EPA's 2008 primary ozone standard. Concurrent with litigation of the 2008 ozone standard, the U.S. EPA continued its regular, periodic review of the ozone NAAQS and is expected to propose revisions by December 1, 2014, with preliminary indications that the U.S. EPA will likely propose a tightened standard based on the June 2014 recommendations of the EPA's Clean Air Act Scientific Advisory Committee (CASAC) to the Administrator and the August 2014 Agency staff *Policy Assessment for the Review of the Ozone National Ambient Air Quality Standards*. In December 2012, the U.S. EPA issued its final revisions to the Agency's particulate matter (PM) NAAQS. In its final rule, the U.S. EPA lowered the annual PM2.5 standard, but declined to issue a new secondary NAAQS to improve urban visibility. The U.S. EPA indicated in its final rule that by 2020 it expects most areas of the country will be in attainment of the new PM2.5 NAAQS based on currently expected regulations, such as the MATS regulation. On March 15, 2013, a number of industry coalitions filed a joint lawsuit challenging the new PM2.5 standard; on May 9, 2014 the D.C. Circuit Court denied these petitions for review.

In addition to these NAAQS, the U.S. EPA also finalized nonattainment designations for certain areas in the United States for the 2010 one-hour SO2 standard on August 5, 2013, and indicated that additional nonattainment areas will be designated in a future rulemaking. U.S. EPA will require states to submit state implementation plans (SIPs) for nonattainment areas by March 25, 2015. With regard to Texas and Maryland, no nonattainment areas were identified in EPA's final designation rule. With regard to Illinois and Pennsylvania, several counties, or portions of counties, in each state were identified as nonattainment. Since the 2010 one-hour SO2 standard was finalized, EPA has issued a series of guidance documents, and proposed a Data Requirement Rule that will be finalized in the summer of 2015 related to requirements for states related to the application of air quality monitoring and modeling in state implementation plans. Nonattainment county compliance with the one-hour SO2 standard is required by March 25, 2018. While significant SO2 reductions will occur as a result of MATS compliance in 2015, Exelon is unable to predict the requirements of pending states' SIPs to further reduce SO2 emissions in support of attainment of the one hour SO2 standard.

Notices and Finding of Violations and Midwest Generation Bankruptcy. In December 1999, ComEd sold several generating stations to Midwest Generation, LLC (Midwest Generation), a subsidiary of Edison Mission Energy (EME). Under the terms of the sale agreement, Midwest Generation and EME assumed responsibility for environmental liabilities associated with the ownership, occupancy, use and operation of the stations, including responsibility for compliance by the stations with environmental laws before their purchase by Midwest Generation. Midwest Generation and EME additionally agreed to indemnify and hold ComEd and its affiliates harmless from claims, fines, penalties, liabilities and expenses arising from third party claims against ComEd resulting from or arising out of the environmental liabilities assumed by Midwest Generation and EME under the terms of the agreement governing the sale. In connection with Exelon's 2001 corporate restructuring, Generation assumed ComEd's rights and obligations with respect to its former generation business, including its rights and obligations under the sale agreement with Midwest Generation and EME.

Under a supplemental agreement reached in 2003, Midwest Generation agreed to reimburse ComEd and Generation for 50% of the specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement.

On December 17, 2012 (Petition Date), EME and certain of its subsidiaries, including Midwest Generation, filed for protection under Chapter 11 of the U.S. Bankruptcy Code.

In 2012, the Bankruptcy Court approved the rejection of an agency agreement related to a coal rail car lease under which Midwest Generation had agreed to reimburse ComEd for all obligations incurred under the coal rail car lease. The rejection left Generation as the party responsible for making all remaining payments under the lease and performing all other obligations thereunder. In January 2013, Generation made the final $10 million payment due under the lease agreement which had been accrued at December 31, 2012.

On March 11, 2014, the Bankruptcy Court for the Northern District of Illinois entered its Order Confirming Debtors' Joint Chapter 11 Plan of Reorganization. On April 1, 2014 (Effective Date), NRG Energy purchased EME's portfolio of generation, including Midwest Generation and the Joint Chapter 11 Plan of Reorganization (Plan) became effective. As part of the Plan, the sale agreement, including the environmental indemnity, and the asbestos cost-sharing agreement were rejected. Creditors were provided 30 days from the Effective Date to file rejection damages claims associated with contracts rejected under the Plan.

During the second quarter of 2013, Exelon filed proofs of claim for approximately $21 million with the Bankruptcy Court for amounts owed by EME and Midwest Generation for the coal rail car lease, ComEd utility payments and certain legal costs. Further, Exelon filed an environmental claim with an unspecified amount that listed the indemnifications that were in place pre-Petition Date and other factors associated with the remediation and a claim under the asbestos cost-sharing agreement with an unspecified amount. As of September 30, 2014, Exelon has not recorded a receivable for the filed proofs of claim because recovery of any amount cannot be assured at this point in the bankruptcy. Exelon will not record claim recoveries unless and until they are realized.

Certain environmental laws and regulations subject current and prior owners of properties or generators of hazardous substances at such properties to liability for remediation costs of environmental contamination. As a prior owner of the generating stations, ComEd (and Generation, through its agreement in Exelon's 2001 corporate restructuring to assume ComEd's rights and obligations associated with its former generation business) could face liability (along with any other potentially responsible parties) for environmental conditions at the stations requiring remediation, with the determination of the allocation among the parties subject to many uncertain factors. ComEd and Generation have reviewed available public information as to potential environmental exposures regarding the Midwest Generation station sites. Midwest Generation publicly disclosed in its March 31, 2014 Form 10-Q that (i) it has accrued a probable amount of approximately $9 million for estimated environmental investigation and remediation costs under CERCLA, or similar laws, for the investigation and remediation of contaminated property at two Midwest Generation plant sites, (ii) it has identified stations for which a reasonable estimate for investigation and/ or remediation cannot be made and (iii) it and the Illinois EPA entered into Compliance Commitment Agreements outlining specified environmental remediation measures and groundwater monitoring activities to be undertaken at its Crawford, Powerton, Joliet, Will County and Waukegan generating stations. At this time, however, ComEd and Generation do not have sufficient information to allow a reasonable assessment of the potential likelihood or magnitude of any remediation requirements that may be asserted. For these reasons, ComEd and Generation are unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to the generating stations and as a result no liability has been recorded as of September 30, 2014. Any liability imposed on ComEd or Generation for environmental matters relating to the generating stations could have a material adverse impact on their future results of operations and cash flows.

Generation increased its reserve for asbestos-related bodily injury claims at December 31, 2013 by $25 million, as a result of Midwest Generation listing such agreement in a January 2014 bankruptcy reorganization plan supplement as an agreement to be rejected in connection with the Plan. As discussed above, the rejection became effective as part of the Plan. Subsequently, Generation increased its reserve by $15 million pursuant to the second quarter 2014 actuarial study of such claims, of which an estimated $6 million pertains to Midwest Generation's share. Midwest Generation publicly disclosed in its March 31, 2014 Form 10-Q, its last public filing prior to its deregistration, that it had $53 million recorded related to asbestos bodily injury claims under the contractual indemnity with ComEd. Exelon and Generation may be entitled to damages associated with the rejection of the agreement. These amounts are considered to be contingent gains and would not be recognized until realized.

Solid and Hazardous Waste

Cotter Corporation. The U.S. EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the U.S. EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. The current estimated cost of the anticipated landfill cover remediation for the site is approximately $42 million, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability. By letter dated January 11, 2010, the U.S. EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the U.S. EPA for review. In June 2012, the U.S. EPA requested that the PRPs perform additional analysis and groundwater sampling as part of the supplemental feasibility study, and subsequently requested additional analysis sampling and modeling that will be conducted throughout 2014 and into 2015. In light of these additional requests, it is unknown when the U.S EPA will propose a remedy for public comment, but will likely be sometime in 2015 at the earliest. Thereafter the U.S. EPA will select a final remedy and enter into a Consent Decree with the PRPs to effectuate the remedy. A complete excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the U.S. EPA would require a complete excavation remedy is remote.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2015 so that settlement discussions could proceed. Based on Generation's preliminary review, it appears probable that Generation has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability.

On February 28, 2012, and April 12, 2012, two lawsuits were filed in the U.S. District Court for the Eastern District of Missouri against 15 and 14 defendants, respectively, including Exelon, Generation and ComEd (the Exelon defendants) and Cotter. The suits allege that individuals living in the North St. Louis area developed some form of cancer due to the Exelon defendants' negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price-Anderson Act. The complaints do not contain specific damage claims. On May 30, 2012, the plaintiffs filed voluntary motions to dismiss the Exelon defendants from both lawsuits which were subsequently granted. Since May 30, 2012, several related lawsuits have been filed in the same court on behalf of various plaintiffs against Cotter and other defendants, but not Exelon. The allegations in these related lawsuits mirror the initially filed lawsuits. In the event of a finding of liability, it is reasonably possible that Exelon would be considered liable due to its indemnification responsibilities of Cotter described above. On March 27, 2013, the U.S. District Court dismissed all state common law actions brought under the initial two lawsuits; and also found that the plaintiffs had not properly brought the actions under the Price-Anderson Act. On July 8, 2013, the plaintiffs filed amended complaints under the Price-Anderson Act. Cotter moved to dismiss the amended complaints and has motions currently pending before the court. At this stage of the litigation, Exelon, Generation, and ComEd cannot estimate a range of loss, if any.

On April 11, 2014, a class action complaint was filed in the U.S. District Court for the Eastern District of Missouri against Cotter and six additional defendants. The complaint alleges that individuals living in the North St. Louis area within a three-mile radius of the West Lake Landfill suffered damage to property or loss of use of property due to the defendants' negligent handling of radioactive materials. On August 22, 2014, the plaintiffs voluntarily dismissed the case without prejudice.

68th Street Dump. In 1999, the U.S. EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In March 2004, BGE and other PRPs formed the 68th Street Coalition and entered into consent order negotiations with the

U.S. EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the U.S. EPA and 19 of the PRPs, including BGE, with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The PRP's submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the U.S. EPA are still subject to U.S. EPA review and selection of a remedy, the range of estimated clean-up costs to be allocated among all of the PRPs is in the range of $50 million to $64 million. On September 30, 2013, U.S. EPA issued the Record of Decision identifying its preferred remedial alternative for the site. The estimated cost for the alternative chosen by U.S. EPA is consistent with the PRPs estimated range of costs noted above. Based on Generation's preliminary review, it appears probable that Generation has liability and has established an appropriate accrual for its share of the estimated clean-up costs. A wholly owned subsidiary of Generation has agreed to indemnify BGE for most of the costs related to this settlement and clean-up of the site.

Rossville Ash Site. The Rossville Ash Site is a 32-acre property located in Rosedale, Baltimore County, Maryland, which was used for the placement of fly ash from 1983-2007. The property is owned by Constellation Power Source Generation, LLC (CPSG). In 2008, CPSG investigated and remediated the property by entering it into the Maryland Voluntary Cleanup Program (VCP) to address any historic environmental concerns and ready the site for appropriate future redevelopment. The site was accepted into the program in 2010 and is currently going through the process to remediate the site and receive closure from MDE. Exelon currently estimates the cost to close the site to be approximately $6 million, which has been fully reserved as of September 30, 2014.

Sauer Dump. On May 30, 2012, BGE was notified by the U.S. EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, Maryland. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. In addition, the U.S. EPA is seeking recovery from the PRPs of $1.7 million for past cleanup and investigation costs at the site. On March 11, 2013, BGE and three other PRP's signed an Administrative Settlement Agreement and Order on Consent with the U.S. EPA which requires the PRP's to conduct a Remedial Investigation and Feasibility Study at the site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The ultimate outcome of this proceeding is uncertain. Since the U.S. EPA has not selected a cleanup remedy and the allocation of the cleanup costs among the PRPs has not been determined, an estimate of the range of BGE's reasonably possible loss, if any, cannot be determined.

Climate Change Regulation. Exelon is subject to climate change regulation or legislation at the Federal, regional and state levels. In 2007, the U.S. Supreme Court ruled that GHG emissions are pollutants subject to regulation under the new motor vehicle provisions of the Clean Air Act. Consequently, on December 7, 2009, the U.S. EPA issued an endangerment finding under Section 202 of the Clean Air Act regarding GHGs from new motor vehicles and on April 1, 2010 issued final regulations limiting GHG emissions from cars and light trucks effective on January 2, 2011. While such regulations do not specifically address stationary sources, such as a generating plant, it is the U.S. EPA's position that the regulation of GHGs under the mobile source provisions of the Clean Air Act has triggered the permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources effective January 2, 2011. Therefore, on May 13, 2010, the U.S. EPA issued final regulations (the Tailoring Rule) relating to these provisions of the Clean Air Act for major stationary sources of GHG emissions that apply to new sources that emit greater than 100,000 tons per year, on a CO_2 equivalent basis, and to modifications to existing sources that result in emissions increases greater than 75,000 tons per year on a CO_2 equivalent basis. These thresholds became effective January 2, 2011, apply for six years and will be reviewed by the U.S. EPA for future applicability thereafter. On July 2, 2012 the U.S. EPA declined to lower GHG permit thresholds in its final "Step 3" Tailoring Rule update. The U.S. EPA will review permit thresholds again in a 2015 rulemaking process. On June 26, 2012, the United States Court of Appeals for the District of Columbia, in a *per curium* decision, dismissed industry and state petitions challenging the U.S. EPA's "Tailpipe Rule" for cars and light duty trucks, the endangerment finding for GHG's from stationary sources, and the Tailoring Rule. On October 15, 2013, the U.S. Supreme Court granted industry petitions to review one aspect of the PSD permitting regulations. Under the PSD regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case by case basis. On June 23, 2014, the U.S. Supreme Court issued an opinion that rejected the U.S. EPA's expansive interpretation of sources that must be subject to GHG regulation. However, the opinion did uphold the U.S. EPA's determination that it could regulate GHG emissions from those sources that are already subject to the PSD rules. As such, large fossil fuel power plants will be subject to regulation of GHGs under the PSD permitting program, with the specific emission limits applied on a case-by-case basis. Therefore, Generation could be significantly affected by the regulations if it were to build new plants or modify existing plants.

On June 25, 2013, President Obama announced "The President's Climate Action Plan," a summary of executive branch actions intended to: reduce carbon emissions; prepare the United States for the impacts of climate change; and lead international efforts to combat global climate change and prepare for its impacts. Concurrent with the announcement of the Administration's plan, the President also issued a Memorandum for the Administrator of the Environmental Protection Agency that focused on power generation sector carbon reductions under the Section 111 New Source Performance Standards (NSPS) section of the federal Clean Air Act. The memorandum directs the U.S. EPA Administrator to issue two sets of proposed rulemakings with regard to power plant carbon emissions under Section 111 of the Clean Air Act.

The first rulemaking, under Section 111(b) of the Clean Air Act, focuses on establishing carbon regulations for new fossil-fuel power plants. This rulemaking was proposed on September 20, 2013 and is to be finalized "in a timely fashion." In the proposed rule, U.S. EPA sets separate standards for fossil-fuel fired utility boilers and natural gas fired stationary combustion turbines.

The second rulemaking, under Section 111(d) of the Clean Air Act, focuses on modified, reconstructed and existing fossil power plants. The proposed rule was published in the Federal Register on June 18, 2014 and is open for public comment until December 1, 2014. The Climate Action Plan calls for the rule to be finalized no later than June 1, 2015, and requires that states submit to U.S. EPA their implementation plans no later than June 30, 2016. The proposed rule establishes emission reduction targets for each state and provides flexibility for each state to determine how to achieve its required reductions, including heat rate improvements at coal-fired power plants, fuel switching from coal to gas, renewable generation and new nuclear facilities, demand side energy efficiency, and the use of market-based instruments.

To the extent that the final Section 111(d) rule results in emission reductions from fossil fuel fired plants, and thereby imposes some form of direct or indirect price of carbon in competitive electricity markets, Exelon's overall low carbon generation portfolio results could benefit.

Litigation and Regulatory Matters

Except to the extent noted below, the circumstances set forth in Note 22 of the Exelon 2013 Form 10-K describe, in all material respects, the current status of litigation matters. The following is an update to that discussion.

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

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

At September 30, 2014 and December 31, 2013, Generation had reserved approximately $103 million and $90 million, respectively, in total for asbestos-related bodily injury claims. As of September 30, 2014, approximately $22 million of this amount related to 265 open claims presented to Generation, while the remaining $81 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary. During the second quarter of 2014, Generation increased its reserve by approximately $15 million, primarily due to increased actual and projected number and severity of claims.

On November 22, 2013, the Supreme Court of Pennsylvania held that the Pennsylvania Workers Compensation Act does not apply to an employee's disability or death resulting from occupational disease, such as diseases related to asbestos exposure, which manifests more than 300 weeks after the employee's last employment-based exposure, and that therefore the exclusivity provision of the Act does not preclude such employee from suing his or her employer in court. The Supreme Court's ruling reverses previous rulings by the Pennsylvania Superior Court precluding current and former employees from suing their employers in court, despite the fact that the same employee was not eligible for workers compensation benefits for diseases that manifest more than 300 weeks after the employee's last employment-based exposure to asbestos. Currently, Exelon, Generation and PECO are unable to predict whether and to what extent they may experience additional claims in the future as a result of this ruling; as such no increase to the asbestos-related bodily injury liability has been recorded as of September 30, 2014. Increased claims activity resulting from this ruling could have a material adverse effect on Exelon's, Generation's and PECO's future results of operations and cash flows.

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

Approximately 486 individuals who were never employees of BGE or certain Constellation subsidiaries have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and certain Constellation subsidiaries in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or certain Constellation subsidiaries and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation's financial results.

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

- the identity of the facilities at which the plaintiffs allegedly worked as contractors;
- the names of the plaintiffs' employers;
- the dates on which and the places where the exposure allegedly occurred; and
- the facts and circumstances relating to the alleged exposure.

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

Continuous Power Interruption (ComEd)

Section 16-125 of the Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law.

On August 18, 2011, ComEd sought from the ICC a determination that ComEd is not liable for damage compensation to customers in connection with the July 11, 2011 storm system that produced multiple power interruptions that in the aggregate affected more than 900,000 customers in ComEd's service territory, as well as for five other storm systems that affected ComEd's customers during June and July 2011 (Summer 2011 Storm Docket). In addition, on September 29, 2011, ComEd sought from the ICC a determination that it was not liable for damage compensation related to the February 1, 2011 blizzard (February 2011 Blizzard Docket).

On June 5, 2013, the ICC approved a complete waiver of liability for five of the six summer storms and the February 2011 blizzard. The ICC held that for the July 11, 2011 storm, 34,559 interruptions were preventable and therefore no waiver should apply. As required by the ICC's Order, ComEd notified relevant customers that they may be entitled to seek reimbursement of incurred costs in accordance with a claims procedure established under ICC rules and regulations. In addition, the ICC found that ComEd did not systematically fail in its duty to provide adequate, reliable and safe service. As a result, the ICC rejected the Illinois Attorney General's request for the ICC to open an investigation into ComEd's infrastructure and storm hardening investments.

Following the ICC's June 26, 2013 denial of ComEd's request for rehearing, on June 27, 2013 ComEd filed an appeal of both the summer and winter storm dockets with the Illinois Appellate Court regarding the ICC's interpretation of Section 16-125 of the Illinois Public Utilities Act. On July 31, 2014, the Illinois Appellate Court reaffirmed the ICC's decision in the appeal of the Summer 2011 Storm Docket and dismissed the appeal of the February 2011 Blizzard Docket. The Illinois Appellate Court's opinion has no accounting impact as ComEd previously established a liability in connection with the June 5, 2013 ICC ruling discussed below. ComEd has asked the Illinois Supreme Court to hear the matter. There is no set time in which the Court must decide whether it will take the case.

As a result of the ICC's June 5, 2013 ruling, ComEd established a liability, which was not material, for potential reimbursements for actual damages incurred by the 34,559 customers covered by the ICC's June 5, 2013 Order. The liability recorded represents the low end of a range of potential losses given that no amount within the range represents a better estimate. ComEd's ultimate liability will be based on actual claims eligible for reimbursement as well as the outcome of the appeal. Although reimbursements for actual damages will differ from the estimated accrual recorded, at this time ComEd does not expect the difference to be material to ComEd's results of operations or cash flows.

ComEd has not recorded an accrual for reimbursement of local governmental emergency and contingency expenses as a range of loss, if any, cannot be reasonably estimated at this time, but may be material to ComEd's results of operations and cash flows.

Telephone Consumer Protection Act Lawsuit (ComEd)

On November 19, 2013, a class action complaint was filed in the Northern District of Illinois on behalf of a single individual and a presumptive class that would include all customers that ComEd enrolled in its Outage Alert text message program. The complaint alleges that ComEd violated the Telephone Consumer Protection Act ("TCPA") by sending approximately 1.2 million text messages to customers without first obtaining their consent to receive such messages. The complaint seeks certification of a class along with statutory damages, attorneys' fees, and an order prohibiting ComEd from sending additional text messages. Such statutory damages could range from $500 to $1,500 per text. ComEd intends to contest the allegations of this suit. In February 2014, ComEd filed a motion to dismiss this class action complaint, which was denied in June 2014. As of September 30, 2014, ComEd has a reserve, which is not material, representing its best estimate of probable loss associated with this class action complaint. As ComEd is unable to predict the ultimate outcome of this proceeding, actual damages may differ from the estimated amount recorded, which may be material to ComEd's results of operations, cash flows, and financial position.

Baltimore City Franchise Taxes (BGE)

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

General (Exelon, Generation, ComEd, PECO and BGE)

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

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

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

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

19. Supplemental Financial Information (Exelon, Generation, ComEd, PECO and BGE)

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants' Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2014 and 2013:

Three Months Ended September 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds[a]					
Regulatory agreement units	$ 55	$ 55	$ —	$ —	$ —
Non-regulatory agreement units	39	39	—	—	—
Net unrealized losses on decommissioning trust funds					
Regulatory agreement units	(107)	(107)	—	—	—
Non-regulatory agreement units	(41)	(41)	—	—	—
Net unrealized gains on pledged assets					
Zion Station decommissioning	7	7	—	—	—
Regulatory offset to decommissioning trust fund-related activities[b]	29	29	—	—	—
Total decommissioning-related activities	(18)	(18)	—	—	—
Investment income	—	—	—	—	1[c]
Long-term lease income	4	—	—	—	—
Interest income related to uncertain income tax positions	25	27	—	—	—
AFUDC — Equity	5	—	—	2	3
Gain on sale of assets	338	338	—	—	—
Other	—	(5)	4	—	—
Other, net	$ 354	$ 342	$ 4	$ 2	$ 4

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

Nine Months Ended September 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds[a]					
Regulatory agreement units	$ 167	$ 167	$ —	$ —	$ —
Non-regulatory agreement units	102	102	—	—	—
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	126	126	—	—	—
Non-regulatory agreement units	100	100	—	—	—
Net unrealized gains on pledged assets					
Zion Station decommissioning	27	27	—	—	—
Regulatory offset to decommissioning trust fund-related activities[b]	(270)	(270)	—	—	—
Total decommissioning-related activities	252	252	—	—	—
Investment income (expense)	1	1	—	(1)	5[c]
Long-term lease income	20	—	—	—	—
Interest income related to uncertain income tax positions	41	53	—	—	—
AFUDC — Equity	17	—	3	5	9
Gain on sale of assets	356	355	1	—	—
Other	15	—	10	1	—
Other, net	$ 702	$ 661	$ 14	$ 5	$ 14

Three Months Ended September 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds[a]					
Regulatory agreement units	$ 138	$ 138	$ —	$ —	$ —
Non-regulatory agreement units	35	35	—	—	—
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	103	103	—	—	—
Non-regulatory agreement units	46	46	—	—	—
Net unrealized losses on pledged assets					
Zion Station decommissioning	(9)	(9)	—	—	—
Regulatory offset to decommissioning trust fund-related activities[b]	(189)	(189)	—	—	—
Total decommissioning-related activities	124	124	—	—	—
Investment income	1	—	—	—	2[c]
Long-term lease income	7	—	—	—	—
AFUDC — Equity	4	—	2	1	1
Gain on sale of assets	10	8	2	—	—
Other	9	2	3	—	1
Other, net	$ 155	$ 134	$ 7	$ 1	$ 4

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

Nine Months Ended September 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds[a]					
Regulatory agreement units	$ 221	$ 221	$ —	$ —	$ —
Non-regulatory agreement units	65	65	—	—	—
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	196	196	—	—	—
Non-regulatory agreement units	70	70	—	—	—
Net unrealized losses on pledged assets					
Zion Station decommissioning	(5)	(5)	—	—	—
Regulatory offset to decommissioning trust fund-related activities[b]	(338)	(338)	—	—	—
Total decommissioning-related activities	209	209	—	—	—
Investment income (expense)	6	(1)	—	(1)	7[c]
Long-term lease income	20	—	—	—	—
Interest income related to uncertain income tax positions	24	3	—	1	—
AFUDC — Equity	16	—	8	3	5
Gain on sale of assets	17	13	2	—	—
Other	19	5	8	1	1
Other, net	$ 311	$ 229	$ 18	$ 4	$ 13

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.
(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 15 — Asset Retirement Obligations of the Exelon 2013 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
(c) Relates to the cash return on BGE's rate stabilization deferral. See Note 5 — Regulatory Matters for additional information regarding the rate stabilization deferral.

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the nine months ended September 30, 2014 and 2013:

Nine Months Ended September 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$1,549	$ 686	$ 438	$169	$215
Regulatory assets	150	—	83	7	60
Amortization of intangible assets, net	33	33	—	—	—
Amortization of energy contract assets and liabilities[a]	83	93	—	—	—
Nuclear fuel[b]	790	790	—	—	—
ARO accretion[c]	251	251	—	—	—
Total depreciation, amortization, accretion and depletion	$2,856	$ 1,853	$ 521	$176	$275

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

Nine Months Ended September 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$1,420	$ 610	$ 413	$164	$194
Regulatory assets	153	—	88	7	58
Amortization of intangible assets, net	33	33	—	—	—
Amortization of energy contract assets and liabilities[a]	342	398	—	—	—
Nuclear fuel[b]	689	689	—	—	—
ARO accretion[c]	207	207	—	—	—
Total depreciation, amortization, accretion and depletion	$2,844	$ 1,937	$ 501	$171	$252

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

Nine Months Ended September 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 437	$ 193	$ 129	$ 28	$ 50
Loss from equity method investments	20	20	—	—	—
Provision for uncollectible accounts	96	10	9	39	38
Stock-based compensation costs	111	—	—	—	—
Other decommissioning-related activity[a]	(102)	(102)	—	—	—
Energy-related options[b]	92	92	—	—	—
Amortization of regulatory asset related to debt costs	8	—	6	2	—
Amortization of rate stabilization deferral	50	—	—	—	50
Amortization of debt fair value adjustment	(45)	(17)	—	—	—
Discrete impacts of EIMA[c]	(32)	—	(32)	—	—
Amortization of debt costs	36	9	4	2	2
Merger commitments[d]	44	44	—	—	—
Other	(17)	2	—	(1)	(11)
Total other non-cash operating activities	$ 698	$ 251	$ 116	$ 70	$129
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 53	$ —	$ 63	$ (14)	$ 6
Other regulatory assets and liabilities	(63)	—	(14)	(14)	(89)
Cash deposits[f]	(280)	(280)	—	—	—
Other current assets	(78)	24	(9)	(48)[h]	25
Other noncurrent assets and liabilities	(168)	(111)	22	1	(9)
Total changes in other assets and liabilities	$ (536)	$ (367)	$ 62	$ (75)	$ (67)
Non-cash investing and financing activities:					
Fair value of net assets recorded upon CENG consolidation[j]	$(3,400)	$ (3,400)	$ —	$ —	$ —
Issuance of equity units[k]	131	—	—	—	—
Uranium procurement[l]	70	70	—	—	—
Indemnification of like-kind exchange position[m]	—	—	4	—	—
Total non-cash investing and financing activities:	$(3,199)	$ (3,330)	$ 4	$ —	$ —

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

Nine Months Ended September 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 621	$ 259	$ 231	$ 32	$ 41
Gain from equity method investments	(7)	(7)	—	—	—
Provision for uncollectible accounts	83	16	(6)	48	25
Stock-based compensation costs	99	—	—	—	—
Other decommissioning-related activity[(a)]	(110)	(110)	—	—	—
Energy-related options[(b)]	87	87	—	—	—
Amortization of regulatory asset related to debt costs	9	—	7	2	—
Amortization of rate stabilization deferral	49	—	—	—	49
Amortization of debt fair value adjustment	(28)	(28)	—	—	—
Discrete impacts from EIMA[(c)]	(206)	—	(206)	—	—
Amortization of debt costs	13	7	3	2	1
Merger integration costs[(e)]	(6)	—	—	—	(6)
Increase in inventory reserve	7	7	—	—	—
Other	(27)	—	(3)	—	(5)
Total other non-cash operating activities	$ 584	$ 231	$ 26	$ 84	$ 105
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ (47)	$ —	$ (63)	$ (10)	$ 26
Other regulatory assets and liabilities	(50)	—	(35)	—	(85)
Settlement of interest rate swaps[(g)]	26	—	—	—	—
Other current assets	(169)	(123)	47	(31)[(h)]	(35)
Other noncurrent assets and liabilities	205	(40)	261[(i)]	(6)	(25)
Total changes in other assets and liabilities	$ (35)	$ (163)	$ 210	$ (47)	$(119)
Non-cash investing and financing activities:					
Consolidated VIE dividend to noncontrolling interest	$ 63	$ 63	$ —	$ —	$ —
Indemnification of like-kind exchange position[(m)]	—	—	175	—	—
Total non-cash investing and financing activities	$ 63	$ 63	$ 175	$ —	$ —

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15 — Asset Retirement Obligations of the Exelon 2013 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 5 — Regulatory Matters for more information.
(d) Reflects the establishment of a reserve related to a MDPSC merger commitment for generation development. See Note 18 — Commitments and Contingencies for additional information.
(e) Relates to integration costs to achieve distribution synergies related to the Constellation merger transaction that were reclassified to a regulatory asset. See Note 5 — Regulatory Matters for more information.
(f) Relates primarily to cash deposits made to ISO's/RTO's.
(g) Relates to settlement of forward starting interest rate swaps that Exelon entered into in anticipation of Continental Wind, LLC non-recourse project financing that was completed on September 30, 2013. See Note 9 — Derivative Financial Instruments for more information on interest rate swaps.
(h) Relates primarily to prepaid utility taxes.
(i) Relates primarily to interest payable related to like-kind exchange tax position. See Note 11 — Income Taxes for discussion of the like-kind exchange tax position.
(j) See Note 6 — Investment in Constellation Energy Nuclear Group, LLC for additional information.

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

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(k) Relates to the present value of the contract payments for the equity units issued by Exelon. See Note 16 — Common Stock for additional information.
(l) Relates to the nuclear fuel procurement contracts for the purchase of fixed quantities of uranium, which was delivered to Generation on June 30, 2014 and September 24, 2014. Generation is required to make payments starting June 30, 2016, with the final payment being due no later than June 30, 2018.
(m) See Note 11 — Income Taxes for discussion of the like-kind exchange tax position.

DOE Smart Grid Investment Grant (Exelon, BGE and PECO). For the nine months ended September 30, 2014, PECO has included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $2 million and reimbursements of $5 million related to PECO's DOE SGIG programs. For the nine months ended September 30, 2013, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $68 million, $22 million and $46 million, respectively, and reimbursements of $64 million, $30 million and $34 million, respectively, related to PECO's and BGE's DOE SGIG programs. See Note 5 — Regulatory Matters for additional information regarding the DOE SGIG.

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants as of September 30, 2014 and December 31, 2013.

September 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$14,932[(a)]	$ 7,868[(a)]	$3,370	$2,972	$2,825
Accounts receivable:					
Allowance for uncollectible accounts	$ 291	$ 55	$ 80	$ 115	$ 41

December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$13,713[(b)]	$ 7,034[(b)]	$3,184	$2,935	$2,702
Accounts receivable:					
Allowance for uncollectible accounts	$ 272	$ 57	$ 62	$ 107	$ 46

(a) Includes accumulated amortization of nuclear fuel in the reactor core of $2,729 million.
(b) Includes accumulated amortization of nuclear fuel in the reactor core of $2,371 million.

PECO Installment Plan Receivables (Exelon and PECO)

PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $19 million as of September 30, 2014 and December 31, 2013. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1 — Significant Accounting Policies of the Exelon 2013 Form 10-K. The allowance for uncollectible accounts balance associated with these receivables at September 30, 2014 of $19 million consists of $1 million, $4 million and $14 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2013 of $18 million consists of $1 million, $4 million and $13 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of September 30, 2014 and December 31, 2013 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1 — Significant Accounting Policies of the Exelon 2013 Form 10-K.

20. Segment Information (Exelon, Generation, ComEd, PECO and BGE)

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

Exelon has nine reportable segments, ComEd, PECO, BGE and Generation's six power marketing reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other regions not considered individually significant and referred to collectively as "Other Regions"; including the South, West and Canada. ComEd, PECO and BGE each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. Exelon's CODM evaluates the performance of and allocates resources to ComEd, PECO and BGE based on net income and return on equity.

The CODMs for ComEd, PECO, and BGE evaluate performance and allocate resources for their respective companies based on net income and return on equity for ComEd, PECO, and BGE each as single integrated businesses.

The foundation of Generation's six reportable segments is based on the geographic location of its assets, and is largely representative of the footprints of an ISO / RTO and/or NERC region. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Regions not considered individually significant:
  - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.

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

- West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
- Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The CODMs for Exelon and Generation evaluate the performance of Generation's power marketing activities and allocate resources based on revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement of operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and sales to its affiliates, ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for Generation's own generation and fuel costs associated with tolling agreements. Generation's other business activities, including retail and wholesale gas, upstream natural gas, proprietary trading, distributed energy, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems, and investments in energy-related proprietary technology are not allocated to regions. Further, Generation's other miscellaneous revenues, unrealized mark-to-market impact of economic hedging activities, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger with Constellation and the consolidation of CENG are also not allocated to a region.

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the three months ended September 30, 2014 and 2013 is as follows:

Three Months Ended September 30, 2014 and 2013

	Generation[a]	ComEd	PECO	BGE	Other[b]	Intersegment Eliminations	Exelon
Total revenues[c]:							
2014	$ 4,412	$ 1,222	$ 693	$ 697	$ 305	$ (417)	$ 6,912
2013	4,255	1,156	728	737	294	(668)	6,502
Intersegment revenues[d]:							
2014	$ 112	$ 1	$ —	$ 3	$ 302	$ (418)	$ —
2013	373	1	1	2	294	(669)	2
Net income (loss):							
2014	$ 849	$ 126	$ 81	$ 49	$ (31)	$ —	$ 1,074
2013	485	126	92	53	(20)	—	736
Total assets:							
September 30, 2014	$ 45,019	$24,845	$10,051	$7,915	$8,713	$ (11,279)	$85,264
December 31, 2013	41,232	24,118	9,617	7,861	8,317	(11,221)	79,924

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. Intersegment revenues for Generation for the three months ended September 30, 2014 include revenue from sales to PECO of $28 million and sales to BGE of $83 million in the Mid-Atlantic region, and sales to ComEd of $1 million in the Midwest region. For the three months ended September 30, 2013, intersegment revenues for Generation include revenue from sales to PECO of $82 million and sales to BGE of $144 million in the Mid-Atlantic region, and sales to ComEd of $143 million in the Midwest region.

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

(b) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.
(c) For the three months ended September 30, 2014 and 2013, utility taxes of $22 million and $21 million, respectively, are included in revenues and expenses for Generation. For the three months ended September 30, 2014 and 2013, utility taxes of $61 million and $65 million, respectively, are included in revenues and expenses for ComEd. For the three months ended September 30, 2014 and 2013, utility taxes of $34 million and $33 million, respectively, are included in revenues and expenses for PECO. For the three months ended September 30, 2014 and 2013, utility taxes of $21 million and $20 million, respectively, are included in revenues and expenses for BGE.
(d) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in Operating revenues in the Consolidated Statements of Operations and Comprehensive Income.

Generation total revenues (three months ended September 30,):

	2014			2013		
	Revenues from external customers[a]	Intersegment revenues	Total Revenues	Revenues from external customers[a]	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 1,285	$ 4	$ 1,289	$ 1,381	$ 10	$ 1,391
Midwest	1,062	(1)	1,061	1,018	(5)	1,013
New England	272	—	272	341	(1)	340
New York	230	2	232	198	(14)	184
ERCOT	303	(1)	302	430	(3)	427
Other Regions[b]	381	(6)	375	278	(7)	271
Total Revenues for Reportable Segments	3,533	(2)	3,531	3,646	(20)	3,626
Other[c]	879	2	881	609	20	629
Total Generation Consolidated Operating Revenues	$ 4,412	$ —	$ 4,412	$ 4,255	$ —	$ 4,255

(a) Includes all electric sales to third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions include the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the date of merger with Constellation and the consolidation of CENG in purchase accounting of $22 million decrease to revenues and $125 million decrease to revenues for the three months ended September 30, 2014 and 2013, respectively, and the elimination of intersegment revenues.

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

Generation total revenues net of purchased power and fuel expense (three months ended September 30,):

	2014			2013		
	RNF from external customers[a]	Intersegment RNF	Total RNF	RNF from external customers[a]	Intersegment RNF	Total RNF
Mid-Atlantic	$ 921	$ 14	$ 935	$ 857	$ 7	$ 864
Midwest	722	(6)	716	606	(5)	601
New England	120	(30)	90	52	10	62
New York	176	10	186	29	(38)	(9)
ERCOT	186	(77)	109	222	(78)	144
Other Regions[b]	157	(89)	68	116	(75)	41
Total Revenues net of purchased power and fuel for Reportable Segments	2,282	(178)	2,104	1,882	(179)	1,703
Other[c]	250	178	428	194	179	373
Total Generation Revenues net of purchased power and fuel expense	$ 2,532	$ —	$ 2,532	$ 2,076	$ —	$ 2,076

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions include the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the date of merger with Constellation and the consolidation of CENG in purchase accounting of $15 million increase to RNF and $44 million decrease to RNF for the three months ended September 30, 2014 and 2013, respectively, and the elimination of intersegment revenues.

Nine Months Ended September 30, 2014 and 2013

	Generation[a][b]	ComEd	PECO	BGE	Other[c]	Intersegment Eliminations	Exelon
Total revenues[d]:							
2014	$ 12,591	$3,484	$2,343	$2,404	$ 924	$ (1,573)	$20,173
2013	11,858	3,395	2,295	2,271	909	(2,003)	18,725
Intersegment revenues[e]:							
2014	$ 630	$ 2	$ 1	$ 21	$ 920	$ (1,574)	$ —
2013	1,083	2	1	10	909	(2,003)	2
Net income (loss):							
2014	$ 1,037	$ 335	$ 255	$ 156	$ (58)	$ —	$ 1,725
2013	795	140	292	160	(152)	—	1,235

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. Intersegment revenues for Generation for the nine months ended September 30, 2014 include revenue from sales to PECO of $165 million and sales to BGE of $290 million in the Mid-Atlantic region, and sales to ComEd of $175 million in the Midwest. For the nine months ended September 30, 2013, intersegment revenues for Generation include revenue from sales to PECO of $321 million and sales to BGE of $356 million in the Mid-Atlantic region, and sales to ComEd of $409 million in the Midwest region, net of $7 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation.
(b) Amounts include activity recorded at CENG from April 1, 2014, the date of integration, through September 30, 2014.
(c) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.

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

(d) For the nine months ended September 30, 2014 and 2013, utility taxes of $67 million and $60 million, respectively, are included in revenues and expenses for Generation. For the nine months ended September 30, 2014 and 2013, utility taxes of $180 million and $182 million, respectively, are included in revenues and expenses for ComEd. For the nine months ended September 30, 2014 and 2013, utility taxes of $99 million and $97 million, respectively, are included in revenues and expenses for PECO. For the nine months ended September 30, 2014 and 2013, utility taxes of $64 million and $62 million, respectively, are included in revenues and expenses for BGE.

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

Generation total revenues (nine months ended September 30,)

	2014			2013		
	Revenues from external customers[a]	Intersegment revenues	Total Revenues	Revenues from external customers[a]	Intersegment revenues	Total Revenues
Mid-Atlantic[b]	$ 3,998	$ (14)	$ 3,984	$ 3,932	$ 11	$ 3,943
Midwest	3,302	11	3,313	3,274	(3)	3,271
New England	1,028	5	1,033	942	(9)	933
New York[b]	614	(1)	613	547	(20)	527
ERCOT	743	(2)	741	1,042	(8)	1,034
Other Regions[c]	1,027	(4)	1,023	708	29	737
Total Revenues for Reportable Segments	10,712	(5)	10,707	10,445	—	10,445
Other[d]	1,879	5	1,884	1,413	—	1,413
Total Generation Consolidated Operating Revenues	$ 12,591	$ —	$12,591	$ 11,858	$ —	$11,858

(a) Includes all wholesale and retail electric sales to third parties and affiliated sales to ComEd, PECO and BGE.
(b) Amounts include activity recorded at CENG from April 1, 2014, the date of integration, through September 30, 2014.
(c) Other regions include the South, West and Canada, which are not considered individually significant.
(d) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the date of merger with Constellation and the consolidation of CENG in purchase accounting of $203 million decrease to revenues and $603 million decrease to revenues, for the nine months ended September 30, 2014 and 2013, respectively, and elimination of intersegment revenues.

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

Generation total revenues net of purchased power and fuel expense (nine months ended September 30,):

	2014			2013		
	RNF from external customers[a]	Intersegment RNF	Total RNF	RNF from external customers[a]	Intersegment RNF	Total RNF
Mid-Atlantic[b]	$ 2,610	$ (60)	$2,550	$ 2,477	$ (2)	$2,475
Midwest	1,856	21	1,877	2,002	(1)	2,001
New England	362	(72)	290	156	(14)	142
New York[b]	289	24	313	14	(31)	(17)
ERCOT	457	(207)	250	477	(120)	357
Other Regions[c]	465	(216)	249	238	(91)	147
Total Revenues net of purchased power and fuel expense for Reportable Segments	6,039	(510)	5,529	5,364	(259)	5,105
Other[d]	(519)	510	(9)	200	259	459
Total Generation Revenues net of purchased power and fuel expense	$ 5,520	$ —	$5,520	$ 5,564	$ —	$5,564

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Amounts include activity recorded at CENG from April 1, 2014, the date of integration, through September 30, 2014.
(c) Other regions include the South, West and Canada, which are not considered individually significant.
(d) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the date of merger with Constellation and the consolidation of CENG in purchase accounting of $78 million decrease to RNF and $386 million decrease to RNF for the nine months ended September 30, 2014 and 2013, respectively, and the elimination of intersegment revenues.

21. Subsequent Event (Exelon and Generation)

On October 24, 2014, Generation entered into a sale agreement to divest its proportional ownership interests in the Keystone and Conemaugh generating facilities and related fuel supply entities in Pennsylvania for total sales proceeds of approximately $475 million, including approximately $60 million of working capital. The transaction, which is subject to customary closing conditions and approvals, is expected to be completed in the fourth quarter of 2014 or first quarter of 2015. The sales price, less costs to complete the sale, is less than the carrying value of the net assets. As a result, Exelon and Generation anticipate recording a pre-tax impairment loss ranging from approximately $350 million to $400 million during the fourth quarter of 2014, which will be recorded within Operating and maintenance expense on Exelon's and Generation's Statement of Operations and Comprehensive Income. The estimated net after-tax cash proceeds of $418 million, excluding estimated working capital, are expected to be used to finance a portion of the acquisition of PHI and for general corporate purposes.

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

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

Exelon Corporation

General

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

- *Generation*, whose integrated business consists of owned, contracted and investments in electric generating facilities managed through customer supply of electric and natural gas products and services, including renewable energy products, risk management services and natural gas exploration and production activities.
  - As a result of the Constellation merger, Generation owns a 50.01% interest in CENG. On April 1, 2014, Generation assumed the operating licenses and corresponding operational control of CENG's nuclear fleet. As a result, Exelon and Generation consolidate CENG's financial position and results of operations into their businesses.
- *ComEd*, whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO*, whose business consists of the purchase and regulated retail sale of electricity and the provision of 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 distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE*, whose business consists of the purchase and regulated retail sale of electricity and the provision of 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 distribution services in central Maryland, including the City of Baltimore.

Exelon has nine reportable segments consisting of Generation's six power marketing reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and other regions in Generation), ComEd, PECO and BGE. See Note 20 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.

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

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

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Executive Overview

Financial Results. The following consolidated financial results reflect the results of Exelon for the three and nine months ended September 30, 2014 compared to the same period in 2013. All amounts presented below are before the impact of income taxes, except as noted.

	Three Months Ended September 30, 2014							Favorable (Unfavorable) Variance
	2014						2013	
	Generation[(a)]	ComEd	PECO	BGE	Other	Exelon	Exelon	
Operating revenues	$ 4,412	$1,222	$ 693	$697	$(112)	$6,912	$6,502	$ 410
Purchased power and fuel	1,880	326	255	297	(110)	2,648	2,743	95
Revenue net of purchased power and fuel[(b)]	2,532	896	438	400	(2)	4,264	3,759	505
Other operating expenses								
Operating and maintenance	1,266	359	204	165	(12)	1,982	1,735	(247)
Depreciation and amortization	253	174	59	78	13	577	530	(47)
Taxes other than income	127	76	42	55	6	306	277	(29)
Total other operating expenses	1,646	609	305	298	7	2,865	2,542	(323)
Equity in earnings of unconsolidated affiliates	1	—	—	—	—	1	37	(36)
Operating income (loss)	887	287	133	102	(9)	1,400	1,254	146
Other income and (deductions)								
Interest expense, net	(89)	(81)	(29)	(26)	(33)	(258)	(234)	(24)
Other, net	342	4	2	4	2	354	155	199
Total other income and (deductions)	253	(77)	(27)	(22)	(31)	96	(79)	175
Income (loss) before income taxes	1,140	210	106	80	(40)	1,496	1,175	321
Income taxes (benefit)	291	84	25	31	(9)	422	439	17
Net income (loss)	849	126	81	49	(31)	1,074	736	338
Net income (loss) attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	78	—	—	3	—	81	(2)	(83)
Net income (loss) attributable to common shareholders	$ 771	$ 126	$ 81	$ 46	$ (31)	$ 993	$ 738	$ 255

	Nine Months Ended September 30,							
	2014						2013	Favorable (Unfavorable)
	Generation[(a)]	ComEd	PECO	BGE	Other	Exelon	Exelon	Variance
Operating revenues	$ 12,591	$3,484	$2,343	$2,404	$(649)	$20,173	$18,725	$ 1,448
Purchased power and fuel	7,071	915	960	1,094	(641)	9,399	8,143	(1,256)
Revenue net of purchased power and fuel[(b)]	5,520	2,569	1,383	1,310	(8)	10,774	10,582	192
Other operating expenses								
Operating and maintenance	3,765	1,040	668	541	(9)	6,005	5,391	(614)
Depreciation and amortization	719	521	176	275	41	1,732	1,606	(126)
Taxes other than income	350	225	122	168	22	887	825	(62)
Total other operating expenses	4,834	1,786	966	984	54	8,624	7,822	(802)
Equity in earnings (loss) of unconsolidated affiliates	(20)	—	—	—	—	(20)	7	(27)
Gain on consolidation of CENG	261	—	—	—	—	261	—	261
Operating income (loss)	927	783	417	326	(62)	2,391	2,767	(376)
Other income and (deductions)								
Interest expense, net	(261)	(241)	(85)	(81)	(54)	(722)	(1,110)	388
Other, net	661	14	5	14	8	702	311	391
Total other income and (deductions)	400	(227)	(80)	(67)	(46)	(20)	(799)	779
Income (loss) before income taxes	1,327	556	337	259	(108)	2,371	1,968	403
Income taxes	290	221	82	103	(50)	646	733	87
Net income (loss)	1,037	335	255	156	(58)	1,725	1,235	490
Net income attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	111	—	—	10	—	121	11	(110)
Net income (loss) attributable to common shareholders	$ 926	$ 335	$ 255	$ 146	$ (58)	$ 1,604	$ 1,224	$ 380

(a) Includes the operations of CENG from April 1, 2014 through September 30, 2014.
(b) The Registrants' evaluate operating performance using the measure of revenue net of purchased power and fuel expense. The Registrants' believe that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013. Exelon's net income attributable to common shareholders was $993 million for the three months ended September 30, 2014 as compared to $738 million for the three months ended September 30, 2013, and diluted earnings per average common share were $1.15 for the three months ended September 30, 2014 as compared to $0.86 for the three months ended September 30, 2013.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $505 million for the three months ended September 30, 2014 as compared to the same period in 2013. The quarter-over-quarter increase in operating revenue net of purchased power and fuel expense was primarily due to the following favorable factors:

- Increase in Generation's revenue net of purchased power and fuel expense of $401 million primarily due to the inclusion of CENG's results for the quarter ended September 30, 2014, favorable portfolio management optimization activities, and a decrease in fuel cost related to the cancellation of the DOE spent nuclear fuel disposal fee, partially offset by a decrease in generation volumes (excluding CENG);
- Increase in Generation's revenue net of purchased power and fuel expense of $21 million due to mark-to-market gains from economic hedging activities of $267 million and $246 million in 2014 and 2013, respectively;
- Decrease in Generation's amortization expense of $59 million for the acquired energy contracts recorded at fair value at the date of the merger with Constellation and the integration with CENG, partially offset by the absence of various joint venture fees due to the integration of CENG;
- Increase in ComEd's revenue net of purchased power expense of $41 million primarily due to higher distribution and transmission revenue from increased capital investments; and
- Increase in BGE's revenue net of purchased power and fuel expense of $9 million primarily due to increased distribution revenue pursuant to increased rates effective in December 2013.

The quarter-over-quarter increase in operating revenue net of purchased power and fuel expense was partially offset by unfavorable weather conditions at ComEd and PECO.

Operating and maintenance expense increased by $247 million for the three months ended September 30, 2014 as compared to the same period in 2013 primarily due to the following unfavorable factors:

- Increase in Generation's labor, contracting and materials costs of $152 million primarily due to the inclusion of CENG's results for the quarter ended September 30, 2014 and increased contracting costs at Generation as a result of increased non-refueling outage days, as well as an increase of $44 million resulting from the loss contingency recorded due to Constellation merger commitments;
- Long lived asset impairments at Generation of $50 million in 2014 compared to $46 million in 2013;
- Increase at ComEd of $26 million primarily related to increased spend on energy efficiency programs and increased uncollectible accounts expense;
- An increase in storm costs at PECO and BGE of $17 million and $8 million, respectively; and
- Increase in contracting costs associated with maintenance related activities at BGE of $13 million.

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

- A decrease in pension and non-pension postretirement benefits expense of $49 million as a result of cost savings primarily at Exelon, Generation, and ComEd for plan design changes for certain OPEB plans, and the favorable impact of higher actuarially assumed pension and OPEB discount rates for 2014, partially offset by the inclusion of CENG's results for the third quarter of 2014; and
- A decrease in nuclear refueling outage costs of $9 million primarily due to a decrease in the number of refueling outage days at Generation during 2014.

Depreciation and amortization expense increased by $47 million primarily due to the inclusion of CENG's results for the quarter ended September 30, 2014 and increased capital expenditures across all operating companies.

Taxes other than income increased by $29 million primarily due to the inclusion of CENG's results for the quarter ended September 30, 2014.

Equity in earnings of unconsolidated affiliates decreased by $36 million primarily due to CENG's operating results being fully consolidated beginning April 1, 2014 and, as a result, are not reflected as equity method earnings in the third quarter of 2014.

Other, net increased by $199 million primarily as a result of the gain recorded on the sale of Generation's ownership interest in generating stations, partially offset by the change in the realized and unrealized gains and losses on NDT funds of the Non-Regulatory Agreement Units.

Exelon's effective income tax rates for the three months ended September 30, 2014 and 2013 were 28.2% and 37.4%, respectively. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Net income (loss) attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends increased $83 million primarily due to the inclusion of CENG's results for the third quarter 2014 not owned by Generation as a result of the consolidation of CENG on April 1, 2014.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013. Exelon's net income attributable to common shareholders was $1,604 million for the nine months ended September 30, 2014 as compared to $1,224 million for the nine months ended September 30, 2013, and diluted earnings per average common share were $1.86 for the nine months ended September 30, 2014 as compared to $1.42 for the nine months ended September 30, 2013.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $192 million for the nine months ended September 30, 2014 as compared to the same period in 2013. The year-over-year increase in operating revenue net of purchased power and fuel expense was primarily due to the following favorable factors:

- Increase in Generation's revenue net of purchased power and fuel expense of $424 million due to inclusion of CENG's results beginning April 1, 2014, increased capacity prices related to the Reliability Pricing Model (RPM) for the PJM Interconnection, LLC (PJM) market, and a decrease in fuel cost related to the cancellation of the DOE spent nuclear fuel disposal fee, partially offset by a decrease in generation volumes (excluding CENG), lower realized energy prices, and higher procurement costs for replacement power and increased fossil fuel expense due to extreme cold weather during the first quarter 2014;
- Decrease in Generation's amortization expense of $308 million for the acquired energy contracts recorded at fair value at the date of the merger with Constellation and the integration with CENG, partially offset by the absence of various joint venture fees due to the integration of CENG;
- Increase in ComEd's revenue net of purchased power expense of $105 million primarily due to increased distribution and transmission revenue resulting from increased capital investment and increased cost recovery associated with energy efficiency programs in 2014;
- Increase in PECO's revenue net of purchased power and fuel expense of $41 million primarily due to increased cost recovery from regulatory programs; and
- Increase in BGE's revenue net of purchased power and fuel expense of $98 million primarily due to increased distribution revenue as a result of the 2013 electric and natural gas distribution rate case orders issued by the Maryland PSC, increased cost recovery for energy efficiency and demand response programs, and increased transmission revenue due to higher rates that took effect in June 2014.

The year-over-year increase in operating revenue net of purchased power and fuel expense was partially offset by a decrease in Generation's revenue net of purchased power and fuel expense of $748 million due to mark-to-market losses of $477 million in 2014 from economic hedging activities compared to mark-to-market gains of $271 million in 2013.

Operating and maintenance expense increased by $614 million for the nine months ended September 30, 2014 as compared to the same period in 2013 primarily due to the following unfavorable factors:

- Increase in Generation's labor, contracting and materials costs of $289 million primarily due to the inclusion of CENG's results beginning April 1, 2014, an increase of $44 million resulting from the loss contingency recorded due to Constellation merger commitments, an increase in nuclear refueling outage costs of $43 million primarily due to an increase in the number of refueling outage days, and an increase of $16 million in the reserve for future asbestos-related bodily injury claims;
- Increase at ComEd of $20 million primarily relating to increased maintenance activities, increased contracting costs associated with EIMA Smart Meter Project assistance, increased spend on energy efficiency programs, and increased uncollectible accounts expense;
- An increase in storm costs at PECO and BGE of $101 million and $21 million, respectively; and
- Increased maintenance activities and uncollectible accounts expense at BGE of $10 million.

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

- A decrease in pension and non-pension postretirement benefits expense of $123 million as a result of cost savings primarily at Exelon, Generation, and ComEd for plan design changes for certain OPEB plans, and the favorable impact of higher actuarially assumed pension and OPEB discount rates for 2014, partially offset by the inclusion of CENG's results beginning April 1, 2014; and
- Long-lived asset impairments of $162 million in 2014 compared to $171 million in 2013.

Depreciation and amortization expense increased by $126 million primarily as a result of the inclusion of CENG's results beginning April 1, 2014, increased depreciation expense across the operating companies for ongoing capital expenditures, and higher costs related to energy efficiency and demand response program expenditures at BGE.

Taxes other than income increased by $62 million primarily due to the inclusion of CENG's results beginning April 1, 2014.

Equity in earnings of unconsolidated affiliates decreased by $27 million primarily due to CENG's operating results being fully consolidated beginning April 1, 2014 and, as a result, are not reflected as equity method earnings.

A $261 million gain was recorded upon consolidation of CENG resulting from the difference in the fair value of CENG's net assets as of April 1, 2014 and the equity method investment previously recorded on Generation's and Exelon's books and the settlement of pre-existing transactions between Generation and CENG.

Interest expense decreased by $388 million primarily as a result of a decrease in interest expense at ComEd related to the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013.

Other, net increased by $391 million primarily as a result of the gain recorded on the sale of Generation's ownership interest in generating stations, favorable settlements in 2014 of certain income tax positions on Constellation's 2009-2012 tax returns, and the change in realized and unrealized gains and losses on NDT funds.

Exelon's effective income tax rates for the nine months ended September 30, 2014 and 2013 were 27.2% and 37.2%, respectively. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Net income (loss) attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends increased $110 million primarily due to the inclusion of CENG's results not owned by Generation as a result of the consolidation of CENG on April 1, 2014.

For further detail regarding the financial results for the three and nine months ended September 30, 2014, including explanation of the non-GAAP measure revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

Adjusted (non-GAAP) Operating Earnings. Exelon's adjusted (non-GAAP) operating earnings for the three months ended September 30, 2014 were $676 million, or $0.78 per diluted share, compared with adjusted (non-GAAP) operating earnings of $667 million, or $0.78 per diluted share for the same period in 2013. Exelon's adjusted (non-GAAP) operating earnings for the nine months ended September 30, 2014 were $1,646 million, or $1.91 per diluted share, compared with adjusted (non-GAAP) operating earnings of $1,722 million, or $2.00 per diluted share for the same period in 2013. In addition to net income attributable to common shareholders, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the three and nine months ended September 30, 2014 as compared to the same period in 2013. The footnotes below the table provide tax expense (benefit) impacts:

	Three Months Ended September 30,			
	2014		2013	
(All amounts after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$ 993	$ 1.15	$ 738	$ 0.86
Mark-to-Market Impact of Economic Hedging Activities[a]	(158)	(0.18)	(148)	(0.17)
Unrealized (Gains) Losses Related to NDT Fund Investments[b]	22	0.03	(24)	(0.03)
Asset Retirement Obligation[c]	(13)	(0.02)	6	0.01
Plant Retirements and Divestitures[d]	(197)	(0.23)	—	—
Long-Lived Asset Impairment[e]	30	0.03	28	0.03
Merger and Integration Costs[f]	64	0.07	26	0.03
Amortization of Commodity Contract Intangibles[g]	(12)	(0.01)	41	0.05
Tax Settlements[h]	(66)	(0.08)	—	—
Noncontrolling Interest[i]	13	0.02	—	—
Adjusted (non-GAAP) Operating Earnings	$ 676	$ 0.78	$ 667	$ 0.78

(All amounts after tax)	Nine Months Ended September 30, 2014		2013	
		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$1,604	$ 1.86	$1,224	$ 1.42
Mark-to-Market Impact of Economic Hedging Activities[a]	293	0.34	(168)	(0.21)
Unrealized Gains Related to NDT Fund Investments[b]	(62)	(0.07)	(37)	(0.04)
Asset Retirement Obligation[c]	(13)	(0.02)	6	0.01
Plant Retirements and Divestitures[d]	(197)	(0.23)	(13)	(0.01)
Long-Lived Asset Impairment[e]	98	0.11	111	0.13
Gain on CENG Integration[j]	(159)	(0.18)	—	—
Merger and Integration Costs[f]	105	0.12	66	0.08
Amortization of Commodity Contract Intangibles[g]	42	0.06	273	0.32
Tax Settlements[h]	(101)	(0.12)	—	—
Noncontrolling Interest[i]	36	0.04	—	—
Remeasurement of Like-Kind Exchange Tax Position[k]	—	—	267	0.31
Amortization of the Fair Value of Certain Debt[l]	—	—	(7)	(0.01)
Adjusted (non-GAAP) Operating Earnings	$1,646	$ 1.91	$1,722	$ 2.00

(a) Reflects the impact of losses (gains) for the three months ended September 30, 2014 and September 30, 2013 (net of taxes of $(105) million and $(99) million, respectively), and nine months ended September 30, 2014 and September 30, 2013 (net of taxes of $188 million and $(112) million, respectively), on Generation's economic hedging activities. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(b) Reflects the impact of unrealized gains (losses) for the three months ended September 30, 2014 and September 30, 2013 (net of taxes of $25 million and $(39) million, respectively), and nine months ended September 30, 2014 and September 30, 2013 (net of taxes of $(22) million and $(66) million, respectively), on Generation's NDT fund investments for Non-Regulatory Agreement Units. See Note 12 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Reflects the impacts of a decrease in Generation's decommissioning obligation for the three and nine months ended September 30, 2014 (net of taxes of $(4) million). Reflects the impacts of the increase in Generation's asset retirement obligation for retired fossil plants for the three and nine months ended September 30, 2013 (net of taxes of $4 million).

(d) Reflects the impact associated with the sale or retirement of Generation's ownership interest in generating stations for the three and nine months ended September 30, 2014 and nine months ended September 30, 2013 (net of taxes of $132 million in 2014, and $5 million in 2013).

(e) Reflects the 2014 charge to earnings for the three and nine months ended September 30, 2014 primarily related to the impairment of certain wind generating assets in the second quarter and certain assets held for sale in the third quarter (net of taxes of $20 million and $62 million, respectively). For the three and nine months ended September 30, 2013, reflects a charge to earnings (net of taxes of $18 million and $70 million, respectively) related to Generation's cancellation of previously capitalized nuclear uprate projects in the second and third quarter and the impairment of certain wind generating assets in the third quarter.

(f) Reflects certain costs incurred for the three months ended September 30, 2014 and September 30, 2013 (net of taxes of $24 million and $16 million, respectively) and for the nine months ended September 30, 2014 and September 30, 2013 (net of taxes of $34 million and $19 million, respectively), associated with the Constellation merger, PHI acquisition, and, at Generation, the CENG integration, including professional fees, employee-related expenses, integration activities, upfront credit facilities fees, merger commitments, and certain pre-acquisition contingencies.

(g) Reflects the non-cash impact for the three months ended September 30, 2014 and 2013 (net of taxes of $(2) million and $26 million, respectively), and nine months ended September 30, 2014 and September 30, 2013 (net of taxes of $44 million and $174 million, respectively), of the amortization of intangible assets, net, related to commodity contracts recorded at fair value at the Constellation merger date and at the CENG integration date.

(h) Reflects a benefit for the three and nine months ended September 30, 2014, related to the favorable settlement in 2014 of certain income tax positions on Constellation's 2009-2012 tax returns (net of tax of $52 million and $70 million, respectively).

(i) Represents adjustments to account for the CENG interest not owned by Generation, where applicable.

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(j) Reflects the non-cash gain recorded upon consolidation of CENG in accordance with the execution of the NOSA on April 1, 2014 (net of taxes of $103 million for the nine months ended September 30, 2014).

(k) Reflects a non-cash charge to earnings for the nine months ended September 30, 2013 (net of taxes of $102 million) resulting from the first quarter 2013 remeasurement of a like-kind exchange tax position taken on ComEd's 1999 sale of fossil generating assets. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

(l) Reflects the non-cash amortization of certain debt for the nine months ended September 30, 2013 (net of taxes of $(5) million) recorded at fair value at the merger date which was retired in the second quarter of 2013. See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

As discussed above, Exelon has incurred and will continue to incur costs associated with the Constellation merger, CENG transaction and PHI acquisition including employee-related expenses (e.g. severance, retirement, relocation and retention bonuses), integration initiatives, and certain pre-acquisition contingencies.

For the three and nine months ended September 30, 2014 and 2013, expense has been recognized for costs incurred to achieve the Constellation merger, CENG transaction and PHI acquisition as follows:

	Pre-tax Expense Three Months Ended September 30, 2014				
Merger, Integration and Acquisition Costs:	**Generation**	**ComEd**	**PECO**	**BGE**	**Exelon**
Employee-Related[(a)]	$ —	$ —	$ —	$—	$ —
Other[(b)]	62	—	—	—	88
Total	$ 62	$ —	$ —	$—	$ 88

	Pre-tax Expense Three Months Ended September 30, 2013				
Merger and Integration Costs:	**Generation**	**ComEd**	**PECO**	**BGE**	**Exelon**
Employee-Related[(a)]	$ 20	$ 2	$ 2	$ 1	$ 27
Other[(b)]	12	—	1	1[(c)]	13
Total	$ 32	$ 2	$ 3	$ 2	$ 40

	Pre-tax Expense Nine Months Ended September 30, 2014				
Merger, Integration and Acquisition Costs:	**Generation**	**ComEd**	**PECO**	**BGE**	**Exelon**
Employee-Related[(a)]	$ 5	$ —	$ —	$—	$ 5
Other[(b)]	87	—	—	—	133
Total	$ 92	$ —	$ —	$—	$ 138

	Pre-tax Expense Nine Months Ended September 30, 2013				
Merger and Integration Costs:	**Generation**	**ComEd**	**PECO**	**BGE**	**Exelon**
Employee-Related[(a)]	$ 32	$ 2	$ 3	$ 1	$ 41
Other[(b)]	42	—	5	(4)	45
Total	$ 74	$ 2	$ 8	$ (3)	$ 86

(a) Costs primarily for employee severance, pension and OPEB expense, and retention bonuses. ComEd established a regulatory asset of $1 million during the nine months ended September 30, 2013. The majority of these costs are expected to be recovered over a five-year period. These costs are not included in the table above.

(b) Costs to integrate CENG and Constellation processes and systems into Exelon, costs to terminate certain Constellation debt agreements, and costs related to certain merger commitments and pre-acquisition contingencies. For the three months ended September 30, 2014, includes professional fees and upfront credit facility fees incurred to acquire PHI. ComEd established a regulatory asset of $2 million and $9 million during the three and nine months ended September 30, 2013, for certain other merger and integration costs, which are not included in the table above. BGE established a regulatory asset of $2 million during the nine months ended September 30, 2013 for certain other merger integration costs, which are not included in the table above.

(c) BGE established a regulatory asset of $6 million at September 30, 2013 for certain 2012 other merger transaction costs as part of the 2013 electric and gas distribution rate case order which are not included in the table above.

As of September 30, 2014, Exelon projects incurring total PHI acquisition and integration related costs over the next five years of approximately $650 million, of which approximately $100 million is expected to be capitalized to Property, plant and equipment. Exelon expects to incur total additional CENG integration related costs of $21 million, primarily in 2014.

Pursuant to the conditions set forth by the MDPSC in its approval of the Exelon and Constellation merger transaction, Exelon committed to provide a package of benefits to BGE customers, and make certain investments in 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 for the requirement to cause construction of a headquarters building in Baltimore for Generation's competitive energy businesses. On March 20, 2013, Generation signed a twenty-year lease agreement that was contingent upon the developer obtaining all required approvals, permits and financing for the construction of a building in Baltimore, Maryland. The operating lease became effective during the second quarter of 2014 when these outstanding contingencies were met by the developer. Construction began late in the second quarter of 2014 and the building is expected to be ready for occupancy 2 years from the start of construction. See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information related to the lease commitments.

Exelon's Strategy and Outlook for the remainder of 2014 and Beyond

Exelon's value proposition and competitive advantage come from its scope and scale across the energy value chain and its core strengths of operational excellence and financial discipline.

Generation's electricity generation strategy is to pursue opportunities that provide generation to load matching and that diversify the generation fleet by expanding Generation's regional and technological footprint. Generation leverages its energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in wholesale power markets. Generation's customer facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the current challenging conditions in competitive energy markets.

Exelon's utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of best practices to achieve improved operational and financial results. Combined, the utilities plan to invest approximately $16 billion over the next five years in smart meter technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Exelon's financial priorities are to maintain investment grade credit metrics at each of Exelon, Generation, ComEd, PECO and BGE, and to return value to Exelon's shareholders with a sustainable dividend throughout the energy commodity market cycle and through earnings growth from attractive investment opportunities.

In pursuing its strategies, Exelon has exposure to various market and financial risks, including the risk of price fluctuations in the power markets. Power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular, the prices of natural gas and coal, which drive the market prices that Generation can obtain for the output of its power plants, (2) the rate of expansion of subsidized low-carbon generation in the markets in which Generation's output is sold, (3) the effects on energy demand due to factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) the impacts of increased competition in the retail channel. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these market pricing issues.

Proposed Merger with Pepco Holdings, Inc. (Exelon)

On April 29, 2014, Exelon and Pepco Holdings, Inc. (PHI) signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. Under the Merger Agreement, PHI's shareholders will receive $27.25 of cash in exchange for each share of PHI common stock. Exelon intends to fund the all-cash transaction using a combination of approximately $3.5 billion of debt, up to $1 billion cash from asset sales primarily at Generation, and the remainder through issuance of equity (including mandatory convertible securities). In addition, Exelon entered into a 364-day $7.2 billion senior unsecured bridge credit facility to support the contemplated transaction and provide flexibility for timing of permanent financing, which has subsequently been reduced to $3.9 billion as a result of the equity issuances and applicable asset divestitures. In connection with the Merger Agreement, Exelon entered into a subscription agreement under which it purchased $90 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities in PHI, in the second quarter of 2014, with additional investments of $18 million to be made quarterly up to a maximum aggregate investment of $180 million. As of September 30, 2014, Exelon has purchased $108 million of PHI preferred securities.

On September 23, 2014, PHI stockholders overwhelmingly approved the merger of PHI and Exelon. Completion of the transaction is conditioned upon approval by the FERC and the public service commissions of the District of Columbia, Delaware, New Jersey and Virginia. Under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act), the transaction cannot be completed until Exelon has made required notifications and given certain information and materials to the Antitrust Division of the United States Department of Justice (DOJ) and until specified waiting period requirements have expired. In addition, the transfer of certain PHI communications licenses requires approval by the Federal Communications Commission.

During the second quarter of 2014, Exelon and PHI ("Joint Applicants") filed approval applications with the FERC and the public service commissions of the District of Columbia, Delaware, New Jersey and Virginia. On August 19, 2014, the Joint Applicants filed their approval application in Maryland. The Joint Applicants also filed notifications with the DOJ in compliance with the requirements of the HSR Act. Exelon's notification was voluntarily withdrawn and refiled in the third quarter.

On October 7, 2014, the Virginia State Corporation Commission issued its Order, granting approval to transfer control of Delmarva Power & Light Company and Potomac Electric Power Company to Exelon. FERC approval is expected in the fourth quarter of 2014, while procedural schedules have been set in the remaining state commission proceedings and final approval decisions are expected in the first half of 2015.

On October 9, 2014, PHI and Exelon each received a request for additional information from the DOJ. The request has the effect of extending the DOJ review period until 30 days after PHI and Exelon each has certified that it has substantially complied with the request. Exelon and PHI will continue to work cooperatively with the DOJ as it conducts its review of the proposed merger.

Exelon and PHI continue to expect to complete the merger in the second or third quarter of 2015.

Through September 30, 2014, Exelon has incurred approximately $57 million of expense associated with the transaction, primarily related to acquisition and integration costs. As part of the applications for approval of the merger, Exelon and PHI have proposed a package of benefits to the PHI utilities' customers, which would result in a direct investment of more than $100 million. The Merger Agreement also provides for termination rights on behalf of both parties. Under certain circumstances, if the Merger Agreement is terminated, PHI may be required to pay Exelon a termination fee ranging from $259 million to $293 million plus certain expenses. If the Merger Agreement does not close due to a regulatory failure, Exelon may be required to pay PHI a termination fee equal to the amount of purchased nonvoting preferred securities (described above), by means of PHI redeeming the outstanding nonvoting preferred securities for no consideration other than the nominal par value of the stock.

Exelon has listed various potential risks relating to the pending merger with PHI (see Item 1A. Risk Factors), including difficulties that may be encountered in satisfying the conditions to completion of the merger and the potential for developments that might have an adverse effect on Exelon and the ability to realize the expected benefits of the merger. Exelon is taking steps to manage these risks and expects that the merger can be completed on a basis favorable to the company's shareholders and customers. Accordingly, Exelon anticipates closing the transaction in the second or third quarter of 2015. Refer to Note 4 — Mergers, Acquisitions and Dispositions for additional information on the merger transaction.

Integrys Energy Group, Inc. (Exelon and Generation)

On July 29, 2014, Generation entered into a Stock Purchase Agreement (the Purchase Agreement) with Integrys Energy Group, Inc. (Integrys). Pursuant to the Purchase Agreement, Integrys agreed to sell its competitive retail electric and natural gas businesses through a sale of all of the stock of its wholly-owned subsidiary, Integrys Energy Services, Inc. (IES), to Generation for an all cash purchase price of $60 million plus adjusted net working capital at the time of the closing. IES's adjusted net working capital balance was approximately $260 million as of September 30, 2014. Pursuant to the Purchase Agreement, Generation has agreed to use its commercially reasonable efforts to replace the guarantees and other credit support currently being provided by Integrys for IES in support of the ongoing competitive retail businesses and to reimburse Integrys for any payments arising pursuant to such arrangements continuing for any post-closing period. The generation and solar asset businesses of IES are excluded from the transaction.

The transaction is expected to close November 1, 2014. The closing of the transaction is subject to certain conditions, including, among others, approval by the FERC and expiration or termination of the applicable waiting period under the HSR Act. The FERC approved the sale of IES to Exelon on September 16, 2014; additionally, the DOJ granted early termination of the HSR Act waiting period effective October 10, 2014. Either party may terminate the Purchase Agreement if the transaction has not been consummated by the 6 month anniversary of the date of the Purchase Agreement. The Purchase Agreement also includes various representations, warranties, covenants, indemnification and other provisions customary for a transaction of this nature. The total costs directly related to the closing of the transaction are not expected to have a material impact on the financial results of Exelon and Generation.

Power Markets

Price of Fuels. The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Forward natural gas prices have declined significantly over the last several years.

Subsidized Generation. The rate of expansion of subsidized generation, including low-carbon generation such as wind and solar energy, in the markets in which Generation's output is sold can negatively impact wholesale power prices, and in turn, Exelon's and Generation's results of operations.

Various states have attempted to implement or propose legislation, regulations or other policies to subsidize new generation development which may result in artificially depressed wholesale energy and capacity prices. For example, the New Jersey legislature enacted the Long Term Capacity Pilot Program Act (LCAPP) in 2011. LCAPP is designed to provide eligible generators with 15-year fixed contracts for the sale of capacity in the PJM capacity market, with the local utilities in New Jersey being required to pay (or receive) the difference between the price those eligible generators receive in the capacity market and the price guaranteed under the 15-year contract. New Jersey ultimately selected three proposals to participate in LCAPP and build new generation in the state.

Exelon and others filed a complaint in federal district court challenging the constitutionality and other aspects of the New Jersey legislation. Similarly, Exelon and others also challenged the selection of the three generation developers. On October 25, 2013, the U.S. District Court in New Jersey issued a judgment order finding that the New Jersey legislation violates the Supremacy Clause of the United States Constitution and the New Jersey (SOCA) contract is unenforceable. The non-prevailing parties sought appeals in federal appellate court in the New Jersey proceeding. On September 11, 2014, the U.S. Court of Appeals for the Third Circuit affirmed the District Court. On October 23, 2013, the New Jersey state court dismissed the New Jersey state proceeding without prejudice, subject to the final outcome of the New Jersey federal litigation. Similarly, on October 24, 2013, the U.S. District Court in Maryland issued a judgment order finding that the MDPSC's Order directing BGE and two other Maryland electric distribution companies to enter into a CfD violates the Supremacy Clause of the United States Constitution, as described in Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements. However, on October 1, 2013, a Maryland State Circuit Court upheld the MDPSC Orders as being within the MDPSC's statutory authority under Maryland state law. This decision is separate from the judgment in the federal litigation that the MDPSC Order is unconstitutional and the CfD unenforceable under federal law. The federal judgment was affirmed on June 2, 2014, by the U.S. Court of Appeals for the Fourth Circuit, and Exelon believes this judgment would prevent enforcement of the CfD even if the Maryland State Circuit Court decision stands. CPV filed for en banc review of the Fourth Circuit decision but its request was denied. We believe that CPV and the MDPSC may seek review by the U.S. Supreme Court of the Fourth Circuit and Third Circuit decisions. CPV, one of the sellers under both a New Jersey and a Maryland contract, filed its two contracts at the FERC which the FERC rejected on August 5, 2014.

As required under their now invalid contracts, generator developers who were selected in the New Jersey and Maryland programs (including CPV) offered and cleared in PJM's capacity market auctions held in May 2012, 2013, and 2014. In addition, CPV has announced its intention to move forward with construction of its New Jersey plant, with or without the challenged state subsidy. Nonetheless, to the extent that the state-required customer subsidies are included under their respective contracts, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in these auctions. While the U.S. Court of Appeals decisions in New Jersey and Maryland are positive developments, continuation of these and similar state efforts, if successful and unabated by an effective minimum offer price rule (MOPR) for future capacity auctions, could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish programs, which could materially adversely affect Exelon's and Generation's market driven position and could have a significant effect on Exelon's and Generation's results of operations, financial position and cash flows.

Accordingly, Exelon continues to work with other market stakeholders and where appropriate through the FERC process to ensure that capacity resources (including those with state-sponsored subsidy contracts and capacity market speculators) cannot inappropriately affect capacity auction prices in PJM.

See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Maryland Order.

Exelon remains active in advocating for competitive markets, while opposing policies that require taxpayers and/or consumers to subsidize or give preferential treatment to specific generation providers or technologies, or that would threaten the reliability and value of the integrated electricity grid.

Energy Demand. Modest economic growth partially offset by energy efficiency initiatives is resulting in positive growth for electricity for ComEd and PECO, and a decrease in projected load for electricity for BGE. ComEd, PECO and BGE are projecting load volumes to increase (decrease) by 0.7%, 0.3% and (1.2)%, respectively, in 2014 compared to 2013.

Retail Competition. Generation's retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. Recently, sustained low forward natural gas and power prices and low market volatility have caused retail competitors to aggressively pursue market share, and wholesale generators (including Generation) to use their retail operations to hedge generation output. These factors have adversely affected overall gross margins and profitability in Generation's retail operations.

Strategic Policy Alignment

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

Exelon's board of directors declared the third quarter 2014 dividend of $0.31 per share on Exelon's common stock. The third quarter dividend was paid on September 10, 2014 to shareholders of record on August 15, 2014. All future quarterly dividends require approval by Exelon's board of directors.

Exelon and Generation evaluate the economic viability of each of their generating units on an ongoing basis. Decisions regarding the future of economically challenged generating assets will be based primarily on the economics of continued operation of the individual plants. If Exelon and Generation do not see a path to sustainable profitability in any of their plants, Exelon and Generation will take steps to retire those plants to avoid sustained losses. Retirement of plants could materially affect Exelon's and Generation's results of operations, financial position, and cash flows through, among other things, potential impairment charges, accelerated depreciation and decommissioning expenses over the plants remaining useful lives, and ongoing reductions to operating revenues, operating and maintenance expenses, and capital expenditures.

Hedging Strategy

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2014 and 2015. This strategy has not changed as a result of recent and pending asset divestitures. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of September 30, 2014, the proportion of expected generation hedged is 98%-101%, 86%-89%, and 55%-58% for 2014, 2015, and 2016, 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 financial exposure through owned or contracted capacity and reflects the divestiture impact of Fore River, Quail Run, and West Valley; but does not reflect the divestiture impact of Generation's interest in Keystone and Conemaugh. See Note 4 — Mergers, Acquisitions and Dispositions and Note 21 — Subsequent Event for more detail regarding the divestitures. 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. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures coal, oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2014 through 2018 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position.

ComEd, PECO and BGE mitigate such exposure through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Growth Opportunities

With an emphasis on innovation and entrepreneurship, Exelon seeks to grow in existing and new markets and establish new businesses in response to, or ahead of, emerging trends. Exelon is currently pursuing growth in both the utility and competitive energy businesses. Management continually evaluates growth opportunities aligned with Exelon's businesses, competencies, assets and markets, leveraging Exelon's expertise in those areas. The proposed acquisition of PHI provides an opportunity to accelerate its regulated growth and provide stable cash flows, earnings accretion, and dividend stability. Additionally, ComEd's, PECO's and BGE's growth efforts are primarily focused on smart meter and smart grid initiatives and they also anticipate making significant future investments in infrastructure modernization and advanced reliability technologies. Generation continues to pursue growth in its existing businesses and markets and further diversification across the competitive energy value chain. Generation's proposed acquisition of Integrys Energy Services, Inc. allows it to expand its retail footprint further in an industry that continues to mature and consolidate and provides hedging and diversification benefits to its existing portfolio. Generation's ongoing investments in the nuclear uprate program, renewables development, new natural gas and biomass generation construction, and our recent investments in technology development illustrates Generation's growth strategy to provide for diversification opportunities while leveraging its expertise and strengths.

Smart Meter and Smart Grid Initiatives.

ComEd's Smart Meter and Smart Grid Investments. ComEd plans to invest approximately $1.3 billion on smart meters and smart grid under EIMA, including $1.0 billion through the AMI Deployment Plan. On June 11, 2014, the ICC approved ComEd's request to accelerate the deployment, which allows for the installation of more than four million smart meters throughout ComEd's service territory by 2018, three years in advance of the originally scheduled 2021 completion date. To date, nearly 500,000 smart meters have been installed in the Chicago area by ComEd.

PECO's Smart Meter and Smart Grid Investments. In 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan, under which PECO will install more than 1.6 million smart meters. PECO plans to spend up to a total of $595 million and $120 million on its smart meter infrastructure and smart grid investments, respectively, of which $200 million has been funded by SGIG.

BGE Smart Grid Initiative. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million electric and gas smart meters at an expected total cost of approximately $480 million, before considering the $200 million SGIG for smart grid and other related initiatives.

See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Initiatives.

Generation Renewable Development. On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 230-MW solar PV project then under development in northern Los Angeles County, California, from First Solar, Inc. The facility became fully operational in 2014. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020. The project has a 25-year PPA with Pacific Gas & Electric Company for the full output of the plant, which has been approved by the CPUC. Total capitalized costs incurred through September 30, 2014 were approximately $1.0 billion. In addition, Generation constructed and placed into service 400 MWs of additional wind generation in 2012 at a cost of $710 million and another 90 MW will be added to Generation's wind portfolio in 2014 with the 50 MW expansion of the Beebe project in Michigan, the output of which is fully contracted under two 20-year PPAs, and the construction of the 40 MW Fourmile Wind project in Maryland to partially satisfy the Exelon-Constellation merger commitments to the State of Maryland.

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Under the nuclear uprate program, Generation has placed into service projects representing 393 MWs of new nuclear generation at a cost of $1.0 billion, which has been capitalized to property, plant and equipment on Exelon's and Generation's consolidated balance sheets. At September 30, 2014, Generation has capitalized $218 million to construction work in progress within property, plant and equipment for nuclear uprate projects expected to be placed in service by the end of 2016, consisting of 139 MWs of new nuclear generation, that are in the installation phase at two nuclear stations: Peach Bottom in Pennsylvania and Dresden in Illinois. The remaining spend associated with these projects is expected to be approximately $200 million through the end of 2016. Generation believes that it is probable that these projects will be completed. If a project is expected not to be completed as planned, previously capitalized costs will be reversed through earnings as a charge to operating and maintenance expense and interest. See Note 7 — Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for further information.

Liquidity

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon, Generation, ComEd, PECO and BGE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.5 billion. See Liquidity and Capital Resources — Credit Matters — Exelon Credit Facilities below.

Exposure to Worldwide Financial Markets. Exelon has exposure to worldwide financial markets including European banks. Disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of September 30, 2014, approximately 29%, or $2.5 billion, of the Registrants' aggregate total commitments were with European banks. The credit facilities include $8.5 billion in aggregate total commitments of which $7.5 billion was available as of September 30, 2014, due to outstanding letters of credit and commercial paper. There were no borrowings under the Registrants' credit facilities as of September 30, 2014. See Note 10 — Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

Tax Matters

See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Environmental Legislative and Regulatory Developments.

Exelon supports the promulgation of certain environmental regulations by the U.S. EPA, including air, water and waste controls for electric generating units. See discussion below for further details. The air and waste regulations will have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and will likely result in the retirement of older, marginal facilities. Due to their low emission generation portfolios, Generation and CENG will not be significantly directly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. Congress that would prohibit or impede the U.S. EPA's rulemaking efforts. The timing of the consideration of such legislation is unknown.

Air Quality. In recent years, the U.S. EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act relating to NAAQS for conventional air pollutants (e.g., NOx, SO2 and particulate matter) as well as stricter technology requirements to control HAPs (e.g., acid gases, mercury and other heavy metals) from electric generation units. The U.S. EPA continues to review and update its NAAQS with a tightened particulate matter NAAQS issued in December 2012 and a review of the current 2008 ozone NAAQS that is expected to result in a proposed revision of the ozone NAAQS sometime in fall 2014. These updates will potentially result in more stringent emissions limits on fossil-fuel electric generating stations. There continues to be opposition among fossil-fuel generation owners to the potential stringency and timing of these air regulations.

In July 2011, the U.S. EPA published CSAPR and in June 2012, it issued final technical corrections. CSAPR requires 28 upwind states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in downwind states. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA had exceeded its authority in certain material aspects with respect to CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. Until the U.S. EPA re-issues CSAPR, Exelon cannot determine the impacts of the rule, including any that would impact power prices. In June 2013, the U.S. Supreme Court granted the U.S. EPA's petition to review the D.C. Circuit Court's CSAPR decision, and on April 29, 2014, the U.S. Supreme reversed the D.C. Circuit Court decision and upheld CSAPR, and remanded the case to the D.C. Circuit Court to resolve the remaining implementation issues. On June 26, 2014, the U.S. EPA filed a motion with the D.C. Circuit Court seeking to have the stay of the CSAPR lifted, and proposed a three-year tolling of the effective dates under the rule so that the first phase of emission budgets would be implemented on January 1, 2015. The U.S. EPA believes that this would allow sufficient time to complete the remaining aspects of the rulemaking before the implementation of the more stringent second phase of emission budgets that, under the tolling proposal, would begin on January 1, 2017.

On December 16, 2011, the U.S. EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that owners of smaller, older, uncontrolled coal units will retire the units rather than make these investments. Coal units with existing controls that do not meet the MATS rule may need to upgrade existing controls or add new controls to comply. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies, or retire the units. Numerous entities challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. On April 15, 2014, the D.C. Circuit Court issued an opinion upholding MATS in its entirety. On July 14, 2014, three petitions for certiorari were filed with the U.S. Supreme Court seeking review of the D.C. Circuit Court decision upholding MATS.

The cumulative impact of these air regulations could be to require power plant operators to expend significant capital to install pollution control technologies, including wet flue gas desulfurization technology for SO2 and acid gases, and selective catalytic reduction technology for NOx. Generation, along with the other co-owners of Conemaugh Generating Station have improved the existing scrubbers and installed Selective Catalytic Reduction (SCR) controls to meet the requirements of MATS. In addition, Keystone already has SCR and flue-gas desulfurization (FGD) controls in place.

On January 15, 2013, EPA issued a final rule for NSPS and National Emissions Standards for Hazardous Air Pollutants (NESHAP) for reciprocating internal combustion engines (RICE NESHAP/NSPS). The final rule allows diesel backup generators to operate for up to 100 hours annually under certain emergency circumstances without meeting emissions limitations, but requires units that operate over 15 hours to burn low sulfur fuel and report key engine information. The final rule eliminates after May 2014 the 50 hour exemption for peak shaving and other non-emergency demand response that was included in the proposed rule and, therefore, is not expected to result in additional megawatts of demand response to be bid into the PJM capacity auction.

In the absence of Federal legislation, the U.S. EPA is also moving forward with the regulation of GHG emissions under the Clean Air Act. The U.S. EPA is addressing the issue of carbon dioxide (CO2) emissions regulation for new and existing electric generating units through the New Source Performance Standards (NSPS) under Section 111 of the Clean Air Act. Pursuant to President Obama's June 25, 2013 memorandum to U.S. EPA, the Agency re-proposed a Section 111(b) regulation for new units in September 2013 that may result in material costs of compliance for CO2 emissions for new fossil-fuel electric generating units, particularly coal-fired units. The Climate Action Plan also required the U.S. EPA to propose by June 2014 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act, and to issue final regulations by June 2015. That proposed rule was published in the Federal Register on June 16, 2014, and is open for public comment until December 1, 2014. The proposed rule establishes emission reduction targets for each state and provides flexibility for each state to determine how to achieve its required reductions, including heat rate improvements at coal-fired power plants, fuel switching from coal to gas, renewable generation and new nuclear facilities, demand side energy efficiency, and the use of market-based instruments. While the nature and impact of the final regulations is not yet known, to the extent that the rule results in emission reductions from fossil fuel fired plants, imposing some form of direct or indirect price of carbon in competitive electricity markets, Exelon's overall low-carbon generation portfolio results would benefit.

Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions.

Water Quality. Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. On October 14, 2014, the U.S. EPA's final Section 316(b) rule became effective. The rule requires that a series of studies and analyses be performed at each facility to determine the best technology available, followed by an implementation period. The timing of the various requirements for each facility is related to the status of its current NPDES permit and the subsequent renewal period. There is no fixed compliance schedule, as this is left to the discretion of the state permitting director.

Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, the impact of compliance with the final rule is unknown. Should a state permitting director determine that a facility is required to install cooling towers to comply with the rule, that facility's economic viability would be called into question. However, the likely impact of the rule has been significantly decreased since the final rule does not mandate cooling towers as a national standard, and the state permitting director is required to apply a cost-benefit test and take into consideration site-specific factors.

Hazardous and Solid Waste. Under proposed U.S. EPA rules issued on June 21, 2010, coal combustion residuals (CCR) would be regulated for the first time under the RCRA. The U.S. EPA is considering several options, including classification of CCR either as a hazardous or non-hazardous waste, under RCRA. Under either option, the U.S. EPA's intention is the ultimate elimination of surface impoundments as a waste treatment process. For plants affected by the proposed rules, this would result in significant capital expenditures and variable operating and maintenance expenditures to convert to dry handling and disposal systems and installation of new waste water treatment facilities. Generation's plants that would be affected by the proposed rules are the Keystone and Conemaugh generating stations in Pennsylvania, which have on-site landfills that meet the requirements of Pennsylvania solid waste regulations for non-hazardous waste disposal. However, until the final rule is adopted, the impact on these facilities is unknown. The U.S. EPA has entered into a Consent Decree which requires that a final rule be issued by December 19, 2014.

See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Other Regulatory and Legislative Actions

Japan Earthquake and Tsunami and the Industry's Response. On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co.

In July 2011, an NRC Task Force formed in the aftermath of the Fukushima Daiichi events issued a report of its review of the accident, including tiered recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The NRC and its staff have issued orders and implementation guidance for commercial reactor licensees operating in the United States. The NRC and its staff are continuing to evaluate additional requirements. Generation has assessed the impacts of the Tier 1 orders and information requests and will continue monitoring the additional recommendations under review by the NRC staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance for Generation, net of expected co-owner reimbursements, for the period from 2014 through 2018 is expected to be between approximately $450 million and $475 million of capital (including approximately $100 million for the CENG plants) and $75 million of operating expense (including approximately $25 million for the CENG plants). As Generation completes the design and installation planning for its actions, Generation will update these estimates. Further, Generation estimates incremental costs of $15 to $20 million per unit at thirteen Mark I and II units (including two CENG units) for the installation of filters on vents, if ultimately required by the NRC. Generation's current assessments are specific to the Tier 1 recommendations as the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See Item 1A. Risk Factors and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Executive Overview of the Exelon 2013 Form 10-K, for additional information.

Financial Reform Legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted in July 2010. Although the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also provides for a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing for certain categories of Swaps, incentives to shift swap activity to exchange trading, margin and capital requirements, and other obligations designed to promote transparency. The Dodd-Frank Act, however, also preserves the ability of end users in the energy industry to hedge their risks without being subject to mandatory clearing. Exelon is conducting its commercial business in a manner that does not require registration as a swap dealer or major swap participant. There are additional rulemakings, however, including the capital and margin rules, which will potentially have an impact on the Registrants' business. Depending on the substance of these final rules, the Registrants could be subject to additional new obligations.

In particular, the proposed regulations addressing collateral and capital requirements and exchange margin cash postings, when final, could require Generation to have increased collateral requirements or cash postings. Generation had previously estimated that it could be required to make up to $1 billion of additional collateral postings under its bilateral credit lines.

Nonetheless, given that Generation is not a swap dealer or major swap participant and the majority of its wholesale portfolio is not comprised of Swaps, the actual amount of additional collateral postings that might be required as a direct result of Dodd-Frank could be lower than Exelon's previous expectations. The actual level of collateral required at any time will depend also on many other factors, including but not limited to market conditions, the extent of its trading activity in Swaps, and Generation's credit ratings. In addition, there will be minimal incremental costs associated with Generation's positions that are currently cleared and subject to exchange margin. Finally, as an end-user, Generation will not be subject to any of the proposed capital requirements that will apply to swap dealers and major swap participants.

Nonetheless, to the extent collateral costs increase as a result of the Dodd-Frank Act, Generation has adequate credit facilities and flexibility in its hedging program to meet any increase, including an increase of $1 billion.

Exelon and Generation continue to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on their results of operations, cash flows or financial position.

ComEd, PECO and BGE could also be subject to some additional Dodd-Frank Act requirements to the extent they were to enter into Swap transactions. However, at this time, management of ComEd, PECO and BGE continue to expect that their companies will not be materially affected by this legislation.

Energy Infrastructure Modernization Act. Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement(s) in effect for the prior year and actual costs incurred for that year. In addition, ComEd's earned rate of return on common equity is required to be within plus or minus 50 basis points ("the collar") of the target rate of return determined as the annual average rate on 30-year treasury notes plus 580 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on distribution revenue. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation.

Formula Rate Tariff and Annual Reconciliation. On April 16, 2014, ComEd filed its annual distribution formula rate update with the ICC. The filing establishes the revenue requirement used to set the rates that will take effect in January 2015 after the ICC's review and approval, which is due by December 2014. The revenue requirement requested is based on 2013 actual costs plus projected 2014 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2013 to the actual costs incurred that year. ComEd’s 2014 filing request includes a total increase to the net revenue requirement of $269 million, reflecting an increase of $174 million for the initial revenue requirement for 2014 and an increase of $95 million related to the annual reconciliation for 2013. The revenue requirement for 2014 provides for a weighted average debt and equity return on distribution rate base of 7.06% inclusive of an allowed return on common equity of 9.25%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2013 provided for a weighted average debt and equity return on distribution rate base of 7.04% inclusive of an allowed return on common equity of 9.20%, reflecting the average rate on 30-year treasury notes plus 580 basis points less a performance metrics penalty of 5 basis points.

On October 15, 2014, the ALJ issued its proposed order in ComEd’s current distribution formula rate proceeding, recommending an increase to the net revenue requirement of $239 million as compared to ComEd’s request of $269 million discussed above. The $30 million reduction, a portion of which may be recoverable through other recovery mechanisms, consisted of a decrease of $20 million for the initial revenue requirement for 2014 and a decrease of $10 million related to the annual reconciliation for 2013. The ALJs proposed order has no independent legal effect as the ICC must vote on a final order by mid December 2014, which may materially vary from the findings and conclusions in the proposed order. If the ICC provides significant changes to ComEd’s filed revenue requirement request, it could have a material impact on ComEd’s results of operations and cash flows.

FERC Ameren Order. In July 2012, FERC issued an order to Ameren Corporation (Ameren) finding that Ameren had improperly included acquisition premiums/ goodwill in its transmission formula rate, particularly in its capital structure and in the application of AFUDC. FERC also directed Ameren to make refunds for the implied increase in rates in prior years. Ameren filed for rehearing of the July 2012 order, which was denied in June 2014. FERC and Ameren are in the process of determining the amount of any potential refund. ComEd believes that the FERC order authorizing its transmission formula rate is distinguishable from the circumstances that led to the July 2012 FERC order in the Ameren case. However, if ComEd were required to exclude acquisition premiums/ goodwill from its transmission formula rate, the impact could be material to ComEd’s results of operations and cash flows.

FERC Order No. 1000 Compliance (ComEd, PECO and BGE). In FERC Order No. 1000, the FERC required public utility transmission providers to enhance their transmission planning procedures and their cost allocation methods applicable to certain new regional and interregional transmission projects. As part of the changes to the transmission planning procedures, the FERC required removal from all FERC-approved tariffs and agreements of a right of first refusal to build certain new transmission facilities. In compliance with the regional transmission planning requirements of Order No. 1000, PJM as the transmission provider submitted a compliance filing to FERC on October 25, 2012. On the same day, certain of the PJM transmission owners, including ComEd, PECO and BGE (collectively, the PJM Transmission Owners), submitted a filing asserting that their contractual rights embodied in the PJM governing documents continue to justify their right of first refusal to construct new reliability (and related) transmission projects and that the FERC should not be allowed to override such rights absent a showing that it is in the public interest to do so under the FERC’s “*Mobile-Sierra*” standard of review. This is a heightened standard of review which the PJM Transmission Owners argued could not be satisfied based on the facts applicable to them. On March 22, 2013, FERC issued an order on the PJM Compliance Filing and the filing of these PJM Transmission Owners (1) rejecting the arguments of those PJM Transmission Owners that changes to the PJM governing documents were entitled to review under the *Mobile-Sierra* standard, (2) accepting most of the PJM filing, removing the right-of-first refusal from the PJM tariffs, and (3) directing PJM to remove certain exceptions that it included in its compliance filing that FERC found did not comply with Order No. 1000. FERC’s order could enable third parties to seek to build certain regional transmission projects that had previously been reserved for the PJM Transmission Owners, potentially reducing ComEd’s, PECO’s and BGE’s opportunities to obtain a financial return with respect to new investments in energy transmission facilities. Numerous parties sought rehearing of the FERC’s March 22, 2013 order, including the PJM Transmission Owners who sought rehearing of the FERC’s rejection of their Mobile-Sierra and related arguments. PJM’s compliance filing was made on July 22, 2013. On

May 15, 2014, FERC denied the rehearing requests except with respect to one issue on when PJM could consider state and local laws in evaluating projects. FERC generally accepted the July 22, 2013, Compliance Filing but required several minor additional changes. FirstEnergy and at least one other party filed an appeal of the May 15, 2014, Order upholding PJM's right of first refusal language in the DC Circuit. Exelon has intervened in the FirstEnergy appeal. Several parties have filed requests for rehearing or clarification concerning the changes set forth in the May 15, 2014 Order.

FERC Transmission Complaint. On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the PHI companies relating to their respective transmission formula rates. BGE's formula rate includes a 10.8% base rate of return on common equity (ROE) for most investments included in its rate base and 11.3% for the remaining transmission investment (the latter of which is conditioned upon crediting the first 50 basis points of any incentive ROE adders). The parties seek a reduction in the base return on equity to 8.7% and changes to the formula rate process. FERC docketed the matter and set April 3, 2013 as the deadline for interventions, protests and answers. Under FERC rules, the revenues subject to refund are limited to a fifteen month period, and the earliest date from which the base return on equity could be adjusted and refunds required is the date of the complaint. On March 19, 2013, BGE filed a motion to dismiss or sever the complaint. On June 19, 2014, FERC issued an order in another case involving New England Transmission Owners (NETOs), changing its methodology to determine ROE rates for public utilities. The result was a reduction in the ROE from 11.14% to 10.57% for the NETOs, with a possible further adjustment in either direction based on additional paper hearing submissions. On July 21, 2014, the NETOs filed a Request for Rehearing and Clarification with FERC of the June 19, 2014 order. Among other things, the NETOs request on rehearing that the 11.14% is reasonable based on the new methodology. Following the paper hearing submissions, FERC again approved a base ROE of 10.57% on October 16, 2014.

On August 21, 2014, FERC issued an order which established hearing and settlement judge procedures for the complaint, and set a refund effective date of February 27, 2013. BGE, the PHI companies and the parties began settlement discussions under the guidance of a FERC administrative law judge on September 23, 2014 and the discussions are expected to continue at least through November. While it is too early in the process to predict the outcome of the settlement discussions, if the parties cannot resolve their differences, the matter will proceed to hearing.

Based on the current status of the settlement discussions, BGE believes it is probable that BGE's base ROE rate will be adjusted, and that a refund to customers of transmission revenue for the maximum fifteen month period will be required. However, BGE is unable to estimate the most likely refund amount at this time, and has therefore established a reserve, which is not material, representing the low end of a reasonably possible estimated range of loss. If FERC were to order a reduction of BGE's base return on equity to 8.7% as sought in the original complaint (while retaining the 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment), the result would be a refund to customers of approximately $13 million, as well as estimated ongoing annual reduction in revenues of approximately $10 million. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

The Maryland Strategic Infrastructure Development and Enhancement Program. In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. Under the new law, following a proceeding before the MDPSC and with the MDPSC's approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. On March 26, 2014, the MDPSC approved as filed BGE's proposed 2014 project list, tariff and associated surcharge amounts, with a surcharge becoming effective April 1, 2014. In February 2014, the residential consumer advocate in Maryland filed an appeal with the Baltimore City Circuit Court to the decision issued by the MDPSC on BGE's infrastructure replacement plan. The residential consumer advocate filed its related legal memorandum on July 7, 2014, claiming that the MDPSC did not apply the appropriate consideration in approving BGE's infrastructure replacement plan and associated surcharge. BGE submitted a response to the appeal on August 6, 2014. On September 5, 2014, the Baltimore City Circuit Court affirmed the MDPSC decision on BGE's infrastructure replacement plan and associated surcharge. On October 10, 2014, the residential consumer advocate noticed its appeal to the Maryland Court of Special Appeals from the judgment entered by the Baltimore City Circuit Court. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Employees

IBEW Local 15's collective bargaining agreements (CBAs) were set to expire in 2013 but were extended by agreement to February 28, 2014. A tentative agreement was reached prior to the expiration and on March 31, 2014, two CBA's with IBEW Local 15 (which represents approximately 5,250 of Exelon's employees) were ratified. The CBA's, one with ComEd and BSC and the other with Generation, extend through September 30, 2019 and April 30, 2019, respectively.

Critical Accounting Policies and Estimates

Management of each of the Registrants makes a number of significant estimates, assumptions and judgments in the preparation of its financial statements. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies and Estimates" in Exelon's, Generation's, ComEd's, PECO's and BGE's combined 2013 Form 10-K for a discussion of the estimates and judgments necessary in the Registrants' accounting for AROs, purchase accounting, asset impairments, depreciable lives of property, plant and equipment, defined benefit pension and other postretirement benefits, regulatory accounting, derivative instruments, taxation, contingencies and revenue recognition. At September 30, 2014, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2013. Exelon and Generation considered the impact of consolidating CENG on the previously disclosed ARO sensitivities and determined that inclusion of CENG balances in these critical accounting estimates impacts the previously disclosed sensitivities generally by 20 to 35 percent which is proportional to the overall increase in the ARO liability from the consolidation of CENG. The ARO sensitivities will be updated in the December 31, 2014 Form 10-K to include the impacts of the CENG consolidation.

Results of Operations

Net Income Attributable to Common Shareholders by Registrant

	Three Months Ended September 30,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2014	2013		2014	2013	
Exelon	$ 993	$ 738	$ 255	$ 1,604	$ 1,224	$ 380
Generation	771	490	281	926	801	125
ComEd	126	126	—	335	140	195
PECO	81	92	(11)	255	285	(30)
BGE	46	50	(4)	146	150	(4)

Results of Operations — Generation

	Three Months Ended September 30, 2014[(a)]	Three Months Ended September 30, 2013	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2014[(a)]	Nine Months Ended September 30, 2013	Favorable (Unfavorable) Variance
Operating revenues	$ 4,412	$ 4,255	$ 157	$ 12,591	$ 11,858	$ 733
Purchased power and fuel expense	1,880	2,179	299	7,071	6,294	(777)
Revenue net of purchased power and fuel[(b)]	2,532	2,076	456	5,520	5,564	(44)
Other operating expenses						
Operating and maintenance	1,266	1,076	(190)	3,765	3,377	(388)
Depreciation and amortization	253	218	(35)	719	643	(76)
Taxes other than income	127	98	(29)	350	292	(58)
Total other operating expenses	1,646	1,392	(254)	4,834	4,312	(522)
Equity in earnings (losses) of unconsolidated affiliates	1	37	(36)	(20)	7	(27)
Gain on consolidation of CENG	—	—	—	261	—	261
Operating income	887	721	166	927	1,259	(332)
Other income and (deductions)						
Interest expense	(89)	(82)	(7)	(261)	(257)	(4)
Other, net	342	134	208	661	229	432
Total other income and (deductions)	253	52	201	400	(28)	428
Income before income taxes	1,140	773	367	1,327	1,231	96
Income taxes	291	288	(3)	290	436	146
Net income	849	485	364	1,037	795	242
Net income (loss) attributable to noncontrolling interests	78	(5)	(83)	111	(6)	(117)
Net income attributable to membership interest	$ 771	$ 490	$ 281	$ 926	$ 801	$ 125

(a) Includes the operations of CENG from April 1, 2014, through September 30, 2014.

(b) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Membership Interest

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013. Generation's net income attributable to membership interest for the three months ended September 30, 2014 increased compared to the same period in 2013 primarily due to higher revenue net of purchased power and fuel expense and an increase in other income, partially offset by increased operating and maintenance expense. The increase in revenue net of purchased power and fuel expense primarily relates to the inclusion of CENG's results on a fully consolidated basis beginning April 1, 2014 and favorable portfolio management optimization activities, partially offset by a decrease in generation volumes, excluding CENG. The increase in operating and maintenance expense is primarily related to the inclusion of CENG's results on a fully consolidated basis beginning April 1, 2014, the loss contingency recorded due to Constellation merger commitments, and increased contracting costs as a result of increased non-refueling outage days. The increase in other income is primarily due to the gain recorded on the sale of Generation's ownership interest in generating stations.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013. Generation's net income attributable to membership interest for the nine months ended September 30, 2014 increased compared to the same period in 2013 primarily due to the gain recognized as a result of the consolidation of CENG and an increase in other income partially offset by decreased revenue net of purchased power and fuel expense and increased operating and maintenance expense. The decrease in revenue net of purchased power and fuel expense primarily relates to mark-to-market losses from economic hedging activities, lower realized energy prices, higher procurement costs for replacement power, increased fossil fuel expense due to extreme cold weather during the first quarter of 2014 and, excluding CENG, a decrease in generation volumes, partially offset by the consolidation of CENG, higher capacity revenues, and a decrease in amortization expense for the acquired energy contracts recorded at fair value at the merger date with Constellation and the consolidation of CENG. The increase in operating and maintenance expense is primarily related to the inclusion of CENG's results on a fully consolidated basis beginning April 1, 2014, the loss contingency recorded due to Constellation merger commitments, and an increase in refueling outage days in 2014. The increase in other income is primarily due to the gain recorded on the sale of Generation's ownership interest in generating stations and an increase in realized and unrealized NDT fund gains.

Revenue Net of Purchased Power and Fuel Expense

The foundation of Generation's six reportable segments is based on the geographic location of its assets, and are largely representative of the footprints of an ISO / RTO and/or NERC region. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within New York ISO, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Regions not considered individually significant:
    - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
    - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
    - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: retail and wholesale gas, investments in natural gas exploration and production activities, proprietary trading, distributed energy, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems and investments in energy-related proprietary technology. Further, the following activities are not allocated to a region, and are reported in Other: unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger with Constellation and the consolidation of CENG; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities using the measure of revenue net of purchased power and fuel expense which is a non-GAAP measurement. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for internally generated energy and fuel costs associated with tolling agreements.

For the three and nine months ended September 30, 2014 and 2013, Generation's revenue net of purchased power and fuel expense by region were as follows:

	Three Months Ended September 30,			
	2014[a]	2013	Variance	% Change
Mid-Atlantic[b]	$ 935	$ 864	$ 71	8.2%
Midwest[c]	716	601	115	19.1%
New England	90	62	28	45.2%
New York	186	(9)	195	n.m.
ERCOT	109	144	(35)	(24.3)%
Other Regions[d]	68	41	27	65.9%
Total electric revenue net of purchased power and fuel expense	2,104	1,703	401	23.5%
Proprietary Trading	23	1	22	n.m.
Mark-to-market gains	267	246	21	8.5%
Other[e]	138	126	12	9.5%
Total revenue net of purchased power and fuel expense	$ 2,532	$ 2,076	$ 456	22.0%

	Nine Months Ended September 30,			
	2014[a]	2013	Variance	% Change
Mid-Atlantic[b]	$ 2,550	$ 2,475	$ 75	3.0%
Midwest[c]	1,877	2,001	(124)	(6.2)%
New England	290	142	148	104.2%
New York	313	(17)	330	n.m.
ERCOT	250	357	(107)	(30.0)%
Other Regions[d]	249	147	102	69.4%
Total electric revenue net of purchased power and fuel expense	5,529	5,105	424	8.3%
Proprietary Trading	43	13	30	n.m.
Mark-to-market gains (losses)	(477)	271	(748)	n.m.
Other[e]	425	175	250	142.9%
Total revenue net of purchased power and fuel expense	$ 5,520	$ 5,564	$ (44)	(0.8)%

(a) Includes the operations of CENG from April 1, 2014 through September 30, 2014.
(b) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.

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(c) Results of transactions with ComEd are included in the Midwest region.
(d) Other Regions include South, West and Canada, which are not considered individually significant.
(e) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the date of the merger with Constellation and the consolidation of CENG in purchase accounting of $15 million increase and $78 million decrease to revenue net of purchased power and fuel expense for the three and nine months ended September 30, 2014, and $44 million decrease and $386 million decrease to revenue net of purchased power and fuel expense for the three and nine months ended September 30, 2013.

Generation's supply sources by region are summarized below:

Supply source (GWh)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Variance	% Change
Nuclear generation				
Mid-Atlantic[(a)]	15,993	12,424	3,569	28.7%
Midwest	24,379	23,741	638	2.7%
New York[(a)]	4,891	—	4,891	n.m.
Total nuclear generation	45,263	36,165	9,098	25.2%
Fossil and renewables[(a)]				
Mid-Atlantic	2,385	2,808	(423)	(15.1)%
Midwest	212	217	(5)	(2.3)%
New England	1,789	3,609	(1,820)	(50.4)%
New York	1	—	1	n.m.
ERCOT	2,331	2,522	(191)	(7.6)%
Other Regions[(c)]	2,285	1,913	372	19.4%
Total fossil and renewables	9,003	11,069	(2,066)	(18.7)%
Purchased power				
Mid-Atlantic[(b)]	1,110	4,289	(3,179)	(74.1)%
Midwest	260	707	(447)	(63.2)%
New England	3,231	2,178	1,053	48.3%
New York[(b)]	—	3,565	(3,565)	(100.0)%
ERCOT	2,184	3,803	(1,619)	(42.6)%
Other Regions[(c)]	4,397	3,244	1,153	35.5%
Total purchased power	11,182	17,786	(6,604)	(37.1)%
Total supply/sales by region[(d)]				
Mid-Atlantic[(e)]	19,488	19,521	(33)	(0.2)%
Midwest[(e)]	24,851	24,665	186	0.8%
New England	5,020	5,787	(767)	(13.3)%
New York	4,892	3,565	1,327	37.2%
ERCOT	4,515	6,325	(1,810)	(28.6)%
Other Regions[(c)]	6,682	5,157	1,525	29.6%
Total supply/sales by region	65,448	65,020	428	0.7%

Supply source (GWh)	Nine Months Ended September 30, 2014	2013	Variance	% Change
Nuclear generation				
Mid-Atlantic[(a)]	43,042	36,980	6,062	16.4%
Midwest	70,223	69,817	406	0.6%
New York[(a)]	8,657	—	8,657	n.m.
Total nuclear generation	121,922	106,797	15,125	14.2%
Fossil and renewables[(a)]				
Mid-Atlantic	8,758	8,764	(6)	(0.1)%
Midwest	948	1,116	(168)	(15.1)%
New England	4,822	9,133	(4,311)	(47.2)%
New York	3	—	3	n.m.
ERCOT	5,541	4,872	669	13.7%
Other Regions[(c)]	5,954	5,598	356	6.4%
Total fossil and renewables	26,026	29,483	(3,457)	(11.7)%
Purchased power				
Mid-Atlantic[(b)]	5,152	10,138	(4,986)	(49.2)%
Midwest	1,491	3,910	(2,419)	(61.9)%
New England	7,591	5,050	2,541	50.3%
New York[(b)]	2,857	10,149	(7,292)	(71.8)%
ERCOT	8,142	12,271	(4,129)	(33.6)%
Other Regions[(c)]	11,406	11,945	(539)	(4.5)%
Total purchased power	36,639	53,463	(16,824)	(31.5)%
Total supply/sales by region[(d)]				
Mid-Atlantic[(e)]	56,952	55,882	1,070	1.9%
Midwest[(e)]	72,662	74,843	(2,181)	(2.9)%
New England	12,413	14,183	(1,770)	(12.5)%
New York	11,517	10,149	1,368	13.5%
ERCOT	13,683	17,143	(3,460)	(20.2)%
Other Regions[(c)]	17,360	17,543	(183)	(1.0)%
Total supply/sales by region	184,587	189,743	(5,156)	(2.7)%

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g. CENG). Nuclear generation for the three months and nine months ended September 30, 2014 includes physical volumes of 3,726 GWh and 7,507 GWh in Mid-Atlantic and 4,891 GWh and 8,657 GWh in New York for CENG.

(b) Purchased power for the three months and nine months ended September 30, 2014 includes physical volumes of 0 GWh and 2,489 GWh in the Mid-Atlantic and 0 GWh and 2,857 GWh in New York as a result of the PPA with CENG. Purchased power for the three months and nine months ended September 30, 2013 includes physical volumes of 3,138 GWh and 8,840 GWh in the Mid-Atlantic and 3,147 GWh and 9,113 GWh in New York as a result of the PPA with CENG. As of the integration date of April 1, 2014, CENG volumes are included in nuclear generation.

(c) Other Regions include South, West and Canada, which are not considered individually significant.

(d) Excludes physical proprietary trading volumes of 3,006 GWh and 2,499 GWh for the three months ended September 30, 2014 and 2013, respectively, and 8,129 GWh and 6,066 GWh for the nine months ended September 30, 2014 and 2013, respectively.

(e) Includes affiliate sales to PECO and BGE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region.

Mid-Atlantic

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013. The $71 million increase in revenue net of purchased power and fuel expense in the Mid-Atlantic was primarily due to the consolidation of CENG, favorable portfolio management optimization activities, and the cancellation of the DOE spent nuclear fuel disposal fee, partially offset by lower capacity revenues and lower generation volumes, excluding CENG.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013. The $75 million increase in revenue net of purchased power and fuel expense in the Mid-Atlantic was primarily due to the consolidation of CENG, the cancellation of the DOE spent nuclear fuel disposal fees, higher capacity revenues, and favorable portfolio management optimization activities, partially offset by higher procurement costs for replacement power, an increase in generation fuel prices, and lower generation volumes, excluding CENG.

Midwest

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013. The $115 million increase in revenue net of purchased power and fuel expense in the Midwest was primarily due to higher capacity revenues and the cancellation of the DOE spent nuclear fuel disposal fee, partially offset by lower realized energy prices.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013. The $124 million decrease in revenue net of purchased power and fuel expense in the Midwest was primarily due to lower realized energy prices, partially offset by increased capacity revenue and the cancellation of the DOE spent nuclear fuel disposal fee.

New England

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013. The $28 million increase in revenue net of purchased power and fuel expense in New England was primarily due to higher realized energy prices and favorable impacts from the restructuring of a fuel supply contract, partially offset by lower generation volume.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013. The $148 million increase in revenue net of purchased power and fuel expense in New England was driven by higher realized energy prices and favorable impacts from the restructuring of a fuel supply contract, partially offset by lower generation volume.

New York

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013. The $195 million increase in revenue net of purchased power and fuel expense in New York was primarily due to the consolidation of CENG.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013. The $330 million increase in revenue net of purchased power and fuel expense in New York was primarily due to the consolidation of CENG.

ERCOT

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013. The $35 million decrease in revenue net of purchased power and fuel expense in ERCOT was primarily due to lower realized energy prices and the termination of an energy supply contract with a retail power supply company that was previously a consolidated variable interest entity. As a result of the termination, Generation no longer has a variable interest in the retail supply company and ceased consolidation of the entity during the third quarter of 2013.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013. The $107 million decrease in revenue net of purchased power and fuel expense in ERCOT was primarily due to increased generation fuel costs, higher procurement costs for replacement power in the second quarter of 2014, and the termination of an energy supply contract with a retail power supply company that was previously a consolidated variable interest entity. As a result of the termination, Generation no longer has a variable interest in the retail supply company and ceased consolidation of the entity during the third quarter of 2013. The decreases were partially offset by higher generation volume in the first quarter of 2014.

Other Regions

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013. The $27 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily due to higher generation volumes and higher realized energy prices, partially offset by increased generation fuel costs.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013. The $102 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily due to higher generation volumes and higher realized energy prices, partially offset by increased generation fuel costs.

Mark-to-market

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013. Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on economic hedging activities were $267 million for the three months ended September 30, 2014 compared to gains of $246 million for the three months ended September 30, 2013. See Notes 8 — Fair Value of Financial Assets and Liabilities and 9 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013. Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market losses on economic hedging activities were $477 million for the nine months ended September 30, 2014 compared to gains of $271 million for the nine months ended September 30, 2013. See Notes 8 — Fair Value of Financial Assets and Liabilities and 9 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Other

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013. The $12 million increase in other revenue net of purchased power and fuel expense was driven by the reduction of amortization of the acquired energy contracts recorded at the date of merger with Constellation and the consolidation of CENG, partially offset by the absence of various joint venture fees due to the integration of CENG.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013. The $250 million increase in other revenue net of purchased power and fuel was driven by the reduction of amortization of the acquired energy contracts recorded at fair value at the date of merger with Constellation and the consolidation of CENG, partially offset by the absence of various joint venture fees due to the integration of CENG.

Nuclear Fleet Capacity Factor and Production Costs

The following table presents nuclear fleet operating data for the three and nine months ended September 30, 2014 as compared to the same periods in 2013, for the Generation-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Nuclear fleet production cost is defined as the costs to produce one MWh of energy, including fuel, materials, labor, contracting and other miscellaneous costs, but excludes depreciation and certain other non-production related overhead costs. Generation considers capacity factor and production costs useful measures comparatively to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Nuclear fleet capacity factor[a]	96.5%	94.8%	94.1%	94.7%
Nuclear fleet production cost per MWh[a]	$ 17.99	$ 18.87	$19.58	$19.14

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC. Reflects ownership percentage of stations operated by Exelon. As of April 1, 2014, CENG is included at ownership.

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013. The nuclear fleet capacity factor increased primarily due fewer refueling outage days, excluding Salem outages during the three months ended September 30, 2014 compared to the same period in 2013. For the three months ended September 30, 2014 and 2013, refueling outage days totaled 18 and 43, respectively. During the same periods, non-refueling outage days totaled 20 and 5, respectively. For the three months ended September 30, 2014 as compared to the same period in 2013, production costs per MWh were lower due to the elimination of the SNF disposal fee in 2014, partially offset by the inclusion of the ownership share of CENG in 2014.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013. The nuclear fleet capacity factor decreased primarily due to more refueling and non-refueling outage days, excluding Salem outages, during the nine months ended September 30, 2014 compared to the same period in 2013. For the nine months ended September 30, 2014 and 2013, refueling outage days totaled 178 and 139, respectively. During the same periods, non-refueling outage days totaled 84 and 42, respectively. For the nine months ended September 30, 2014 as compared to the same period in 2013, production costs per MWh were higher due to higher refueling and non-refueling days and due to the inclusion of the ownership share of CENG, partially offset by the elimination of the SNF disposal fee in 2014.

Operating and Maintenance

The changes in operating and maintenance expense for the three and nine months ended September 30, 2014 compared to the same period in 2013, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)[(a)]	Nine Months Ended September 30, Increase (Decrease)[(a)]
Labor, other benefits, contracting, materials	$ 152	$ 289
Accretion expense	28	56
Nuclear refueling outage costs, including the co-owned Salem plants[(b)]	(9)	43
Regulatory fees and assessment	16	34
Increase in asbestos reserve	—	16
Pension and non-pension postretirement benefits expense	(22)	(56)
Merger and integration costs	29	17
Impairment of long-lived assets[(c)]	4	(23)
Other	(8)	12
Increase in operating and maintenance expense	$ 190	$ 388

(a) Includes the operations of CENG, from April 1, 2014 through September 30, 2014.
(b) Reflects the impact of refueling outage days in 2014.
(c) Reflects the impact of the charge to earnings related to the cancellation of previously capitalized nuclear uprate projects in 2013 and the impairment of certain wind generating assets in 2013 and 2014 and certain assets held for sale in 2014.

Depreciation and Amortization

The increase in depreciation and amortization expense for the three and nine months ended September 30, 2014 compared to the three and nine months ended September 30, 2013 was primarily due the inclusion of CENG's results beginning April 1, 2014 and an increase in ongoing capital expenditures.

Taxes Other Than Income

The increase in taxes other than income for the three and nine months ended September 30, 2014 as compared to the three and nine months ended September 30, 2013 was primarily due to the inclusion of CENG's results beginning April 1, 2014 and an increase in payroll taxes and real estate taxes.

Equity in Losses of Unconsolidated Affiliates

The unfavorable decrease in equity in losses of unconsolidated affiliates for the three and nine months ended September 30, 2014 as compared to the three and nine months ended September 30, 2013 was due to the decrease in non-cash amortization of the fair value basis difference recorded at the Constellation merger date, offset by equity in losses in CENG in 2013. CENG's operating results were fully consolidated beginning April 1, 2014 and, as a result, are not reflected as equity method earnings in the second and third quarters of 2014.

Interest Expense

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013. Interest expense for three months ended September 30, 2014 compared to same period in 2013 remained relatively level.

N*ine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013.* Interest expense for nine months ended September 30, 2014 compared to same period in 2013 remained relatively level.

Other, Net

The increase in other, net for the three and nine months ended September 30, 2014 compared to the same periods in 2013 primarily reflects the gain recorded on the sale of Generation's equity interest in the 417 MW Safe Harbor Water Power Corporation during the third quarter of 2014. Refer to Note 4 — Mergers, Acquisitions and Dispositions for additional information related to the sale of Generation's ownership interests in generating units. The increase in other, net also reflects the change in the realized and unrealized gains and losses related to the NDT funds of its Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $(16) million and $43 million for the three months ended September 30, 2014 and 2013, respectively, and $50 million and $73 million for the nine months ended September 30, 2014 and 2013, respectively, related to the contractual elimination of income tax expense (benefit) associated with the NDT funds of the Regulatory Agreement Units. Refer to Note 12 — Nuclear Decommissioning for additional information regarding NDT funds.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in other, net for the three and nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014[(a)]	2013	2014[(a)]	2013
Net unrealized gains (losses) on decommissioning trust funds	$ (41)	$ 46	$ 100	$ 70
Net realized gains on sale of decommissioning trust funds	17	22	42	25

(a) Includes results of CENG from April 1, 2014 through September 30, 2014.

Effective Income Tax Rate

The effective income tax rate was 25.5% and 21.9% for the three and nine months ended September 30, 2014, respectively, compared to 37.3% and 35.4% for the same periods during 2013. See Note 11 — Income Taxes of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in the effective income tax rate.

Results of Operations — ComEd

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	Favorable (Unfavorable) Variance
Operating revenues	$ 1,222	$ 1,156	$ 66	$ 3,484	$ 3,395	$ 89
Purchased power expense	326	301	(25)	915	931	16
Revenue net of purchased power expense[(a)]	896	855	41	2,569	2,464	105
Other operating expenses						
Operating and maintenance	359	333	(26)	1,040	1,020	(20)
Depreciation and amortization	174	164	(10)	521	501	(20)
Taxes other than income	76	80	4	225	225	—
Total other operating expenses	609	577	(32)	1,786	1,746	(40)
Operating income	287	278	9	783	718	65
Other income and (deductions)						
Interest expense, net	(81)	(74)	(7)	(241)	(503)	262
Other, net	4	7	(3)	14	18	(4)
Total other income and (deductions)	(77)	(67)	(10)	(227)	(485)	258
Income before income taxes	210	211	(1)	556	233	323
Income taxes	84	85	1	221	93	(128)
Net income	$ 126	$ 126	$ —	$ 335	$ 140	$ 195

(a) ComEd evaluates its operating performance using the measure of revenue net of purchased power expense. ComEd believes that revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013. ComEd's net income for the three months ended September 30, 2014 was relatively consistent to the same period in 2013, primarily due to increased distribution and transmission revenues resulting from increased capital investment, offset by unfavorable weather.

Nine months ended September 30, 2014 Compared to Nine months ended September 30, 2013. ComEd's net income for the nine months ended September 30, 2014 was higher than the same period in 2013, primarily due to the interest expense and related income tax effects of the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013, as well as increased distribution and transmission revenue resulting from increased capital investment. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information on the like-kind exchange tax position.

Operating Revenues Net of Purchased Power Expense

There are certain drivers of revenue that are fully offset by their impact on purchased power expense, such as commodity procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on revenue net of purchased power expense. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process.

All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact ComEd's volume of deliveries, but do affect ComEd's operating revenue related to supplied energy, which is fully offset in purchased power expense. Therefore, customer choice programs have no impact on revenue net of purchased power expense.

The number of retail customers participating in customer choice programs was 2,422,850 and 2,621,356 at September 30, 2014, and 2013, respectively, representing 63% and 68% of total retail customers, respectively. Retail energy purchased from competitive electric generation suppliers represented 79% and 80% of ComEd's retail kWh sales for the three and nine ended September 30, 2014, respectively, as compared to 81% and 64% for the three and nine months ended September 30, 2013, respectively.

The changes in ComEd's revenue net of purchased power expense for the three and nine ended September 30, 2014, compared to the same periods in 2013 consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Weather	$ (27)	$ (11)
Volume	1	7
Electric distribution revenues	15	56
Transmission revenues	19	21
Regulatory required programs	11	39
Uncollectible accounts recovery, net	27	15
Pricing and customer mix	3	6
Revenue subject to refund	—	(9)
Other	(8)	(19)
Increase in revenue net of purchased power expense	$ 41	$ 105

Weather. The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as "favorable weather conditions" because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand. For the three and nine months ended September 30, 2014 compared to the same period in 2013, operating revenues net of purchased power expense were lower due to unfavorable 2014 summer weather conditions in ComEd's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd's service territory with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd's service territory for the three and nine months ended September 30, 2014, and 2013, consisted of the following:

Heating and Cooling Degree-Days	2014	2013	Normal	% Change From 2013	% Change From Normal
Three Months Ended September 30,					
Heating Degree-Days	111	79	119	40.5%	(6.7)%
Cooling Degree-Days	537	668	613	(19.6)%	(12.4)%
Nine Months Ended September 30,					
Heating Degree-Days	4,680	4,116	4,048	13.7%	15.6%
Cooling Degree-Days	796	908	831	(12.3)%	(4.2)%

Volume. Revenue net of purchased power expense increased as a result of higher delivery volume, exclusive of the effects of weather, reflecting increased average usage per residential customer as compared to the same nine month period in 2013.

Electric Distribution Revenue. EIMA provides for a performance-based rate formula, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Distribution revenue varies from year to year based on fluctuations in the underlying costs, investments being recovered and other billing determinants. In addition, ComEd's earned rate of return on common equity is required to be within plus or minus 580 basis points ("the collar") of the target rate of return determined as the annual average rate on 30-year treasury notes plus 9 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on distribution revenue. During the three and nine months ended September 30, 2014, ComEd recorded increased electric distribution revenue primarily due to increased capital investment and increased cost recovery associated with energy efficiency programs. The increase was partially offset due to the one-time reduction for expenses associated with OPEB plan design changes. See Operating and Maintenance Expense below, and Note 5 — Regulatory Matters and Note 13 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's rate formula pursuant to EIMA and the OPEB plan design changes.

Transmission Revenues. ComEd's transmission rates are established based on a FERC-approved formula. ComEd's most recent annual formula rate update, filed in April 2014, reflects 2013 actual costs plus forecasted 2014 capital additions. Transmission revenue net of purchased power expense vary from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants, such as the highest daily peak load from the previous calendar year. For the three and nine months ended September 30, 2014, ComEd recorded increased transmission revenues due to increased capital investment. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. Revenues related to regulatory required programs represents the recoveries from customers for costs of various legislative and regulatory programs on a full and current basis through approved regulated rates. Programs include ComEd's energy efficiency and demand response and purchased power administrative costs. An equal and offsetting amount has been reflected in operating and maintenance expense during the periods presented.

Uncollectible Accounts Recovery, Net. Represents recoveries under ComEd's uncollectible accounts tariff. See the operating and maintenance expense discussion below for additional information on this tariff.

Pricing and Customer Mix. The increase in revenue net of purchased power as a result of pricing and customer mix is primarily attributable to higher overall effective rates due to decreased usage across all major customer classes and change in customer mix for the three and nine months ended September 30, 2014, as compared to the same periods in 2013.

Revenue Subject to Refund. ComEd records revenues subject to refund based upon its best estimate of customer collections that may be required to be refunded. For the nine months ended September 30, 2014 ComEd recorded $9 million of revenue subject to refund associated with Rider AMP. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, revenue from other utilities for mutual assistance programs and recoveries of environmental costs associated with MGP sites, for which an equal and offsetting amount is reflected in depreciation and amortization expense during the periods presented.

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Operating and Maintenance Expense

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Increase (Decrease)	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	Increase (Decrease)
Operating and maintenance expense — baseline	$ 314	$ 299	$ 15	$ 873	$ 892	$ (19)
Operating and maintenance expense — regulatory required programs[(a)]	45	34	$ 11	167	128	$ 39
Total operating and maintenance expense	$ 359	$ 333	$ 26	$ 1,040	$ 1,020	$ 20

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for the three and nine months ended September 30, 2014 compared to the same periods in 2013, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ 19	$ 34
Pension and non-pension postretirement benefits expense	(24)	(61)
Storm-related costs	(5)	(11)
Uncollectible accounts expense — provision[(a)]	4	6
Uncollectible accounts expense — recovery, net[(a)]	23	9
Other	(2)	4
	15	(19)
Regulatory required programs		
Energy efficiency and demand response programs	11	39
	11	39
Increase in operating and maintenance expense	$ 26	$ 20

(a) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. During the three and nine months ended September 30, 2014, ComEd recorded a net increase in operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery and customers purchasing electricity from competitive electric generation suppliers as a result of municipal aggregation. An equal and offsetting increase has been recognized in operating revenues for the periods presented.

Depreciation and Amortization

Depreciation and amortization expense increased during the three and nine months ended September 30, 2014, compared to the same periods in 2013, primarily due to ongoing capital expenditures and decreased regulatory asset amortization related to lower MGP remediation expenditures. An equal and offsetting amount for the amortization expense related to the MGP remediation expenditures is reflected in operating revenues during the periods presented.

Taxes Other Than Income

Taxes other than income taxes, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income taxes remained relatively flat for the three and nine months ended September 30, 2014, compared to the same periods in 2013.

Interest Expense, Net

The changes in interest expense, net for the three and nine months ended September 30, 2014, compared to the same period in 2013, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Interest expense related to uncertain tax positions[a]	$ 1	$ (274)
Interest expense on debt (including financing trusts)	6	12
Increase in interest expense, net	$ 7	$ (262)

(a) Primarily reflects the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013. See Note 11 — Income Taxes of the Combined Notes to the Consolidated Financial Statements for additional information.

Effective Income Tax Rate

The effective income tax rate was 40.0% for the three months ended September 30, 2014 compared to 40.3% for the same period during 2013. The effective income tax rate was 39.7% for the nine months ended September 30, 2014 compared to 39.9% for the same period during 2013. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

ComEd Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	% Change	Weather-Normal % Change
Retail Deliveries[a]				
Residential	7,332	8,188	(10.5)%	1.3%
Small commercial & industrial	8,366	8,680	(3.6)%	(0.6)%
Large commercial & industrial	7,245	7,381	(1.8)%	—%
Public authorities & electric railroads	301	329	(8.5)%	(8.3)%
Total Retail Deliveries	23,244	24,578	(5.4)%	0.1%

Retail Deliveries to Customers (in GWhs)	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	% Change	Weather-Normal % Change
Retail Deliveries[a]				
Residential	20,920	21,154	(1.1)%	1.4%
Small commercial & industrial	24,456	24,385	0.3%	0.1%
Large commercial & industrial	21,109	20,932	0.8%	0.6%
Public authorities & electric railroads	1,001	997	0.4%	(1.3)%
Total Retail Deliveries	67,486	67,468	—%	0.6%

Number of Electric Customers	As of September 30, 2014	As of September 30, 2013
Residential	3,486,438	3,465,635
Small commercial & industrial	367,446	366,216
Large commercial & industrial	1,992	1,978
Public authorities & electric railroads	4,821	4,860
Total	3,860,697	3,838,689

Electric Revenue	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	% Change	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	% Change
Retail Sales[a]						
Residential	$ 566	$ 529	7.0%	$ 1,572	$1,589	(1.1)%
Small commercial & industrial	349	322	8.4%	1,033	945	9.3%
Large commercial & industrial	115	112	2.7%	343	327	4.9%
Public authorities & electric railroads	10	12	(16.7)%	35	35	—%
Total Retail	1,040	975	6.7%	2,983	2,896	3.0%
Other Revenue[b]	182	181	0.6%	501	499	0.4%
Total Electric Revenues	$ 1,222	$ 1,156	5.7%	$ 3,484	$3,395	2.6%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.

(b) Other revenue primarily includes transmission revenue from PJM. Other items include rental revenue, revenue related to late payment charges, revenue from other utilities for mutual assistance programs and recoveries of environmental costs associated with MGP sites.

Results of Operations — PECO

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	Favorable (Unfavorable) Variance
Operating revenues	$ 693	$ 728	$ (35)	$ 2,343	$ 2,295	$ 48
Purchased power and fuel	255	289	34	960	953	(7)
Revenue net of purchased power and fuel[(a)]	438	439	(1)	1,383	1,342	41
Other operating expenses						
Operating and maintenance	204	186	(18)	668	554	(114)
Depreciation and amortization	59	57	(2)	176	171	(5)
Taxes other than income	42	41	(1)	122	121	(1)
Total other operating expenses	305	284	(21)	966	846	(120)
Operating income	133	155	(22)	417	496	(79)
Other income and (deductions)						
Interest expense, net	(29)	(29)	—	(85)	(86)	1
Other, net	2	1	1	5	4	1
Total other income and (deductions)	(27)	(28)	1	(80)	(82)	2
Income before income taxes	106	127	(21)	337	414	(77)
Income taxes	25	35	10	82	122	40
Net income	81	92	(11)	255	292	(37)
Preferred security dividends and redemption	—	—	—	—	7	7
Net income attributable to common shareholders	$ 81	$ 92	$ (11)	$ 255	$ 285	$ (30)

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income attributable to common shareholders

Three Months Ended September 30, 2014 Compared to Three Months Ended September 30, 2013. The decrease in net income attributable to common shareholders was driven primarily by unfavorable weather included in Revenue, net of purchased power and fuel and an increase in operating and maintenance expense, due to an increase in storm costs, partially offset by a reduction in income tax expense.

Nine Months Ended September 30, 2014 Compared to Nine Months Ended September 30, 2013. The decrease in net income attributable to common shareholders was driven primarily by an increase in operating and maintenance expense partially offset by an increase in operating revenues net of purchase power and fuel expense, a reduction in income tax expense and a reduction of PECO's redemption costs as a result of the redemption of all of PECO's outstanding preferred securities on May 1, 2013.

Operating Revenues, Purchased Power and Fuel Expense

Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments at least quarterly that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with the PAPUC's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and gas revenue net of purchased power and fuel expense.

Electric and gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customer's choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and gas revenue net of purchased power and fuel expense. The number of retail customers purchasing electricity from a competitive electric generation supplier was 537,000 and 518,000 at September 30, 2014 and 2013, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 70% of PECO's retail kWh sales for both the three and nine months ended September 30, 2014, compared to 69% and 68% for the three and nine months ended September 30, 2013, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 76,200 and 60,400 at September 30, 2014 and 2013, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 27% and 22% of PECO's mmcf sales for the three and nine months ended September 30, 2014, respectively, compared to 23% and 19% for the three and nine months ended September 30, 2013.

The changes in PECO's operating revenues net of purchased power and fuel expense for the three and nine months ended September 30, 2014 compared to the same period in 2013 consisted of the following:

	Three Months Ended September 30, Increase (Decrease)			Nine Months Ended September 30, Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$ (16)	$ (1)	$ (17)	$ (7)	$16	$ 9
Volume	1	1	2	8	3	11
Pricing	2	1	3	(4)	(2)	(6)
Regulatory required programs	13	—	13	26	—	26
Other	(2)	—	(2)	1	—	1
Total increase (decrease)	$ (2)	$ 1	$ (1)	$ 24	$17	$ 41

Weather. The demand for electricity and gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and gas. Conversely, mild weather reduces demand. During the three months ended September 30, 2014 compared to the same period in 2013, operating revenues net of purchased power and fuel expense were lower due to unfavorable summer weather conditions in PECO's service territory.

During the nine months ended September 30, 2014 compared to the same period in 2013, operating revenues net of purchased power and fuel expense were higher due to the impact of favorable 2014 winter weather conditions, partially offset by unfavorable 2014 summer weather conditions in PECO's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the three and nine months ended September 30, 2014 compared to the same periods in 2013 and normal weather consisted of the following:

Heating and Cooling Degree-Days	2014	2013	Normal	% Change From 2013	% Change From Normal
Three Months Ended September 30,					
Heating Degree-Days	14	36	35	(61.1)%	(60.0)%
Cooling Degree-Days	911	928	934	(1.8)%	(2.5)%
Nine Months Ended September 30,					
Heating Degree-Days	3,251	2,897	2,974	12.2%	9.3%
Cooling Degree-Days	1,286	1,346	1,282	(4.5)%	0.3%

Volume. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three and nine months ended September 30, 2014 compared to the same period in 2013, primarily reflects the impact of moderate economic and customer growth and a shift in the volume profile across classes from lower priced classes to higher priced classes, partially offset by energy efficiency initiatives on customer usages.

Pricing. The increase in operating revenues net of purchased power and fuel expense as a result of pricing for the three months ended September 30, 2014 compared to the same period in 2013 is primarily attributable to higher overall effective rates due to decreased electric usage across all customer classes.

The decrease in operating revenues net of purchased power and fuel expense as a result of pricing for the nine months ended September 30, 2014 compared to the same period in 2013 is primarily attributable to lower overall effective rates due to increased usage in the residential customer class.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Operating and Maintenance Expense

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Increase (Decrease)	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	Increase (Decrease)
Operating and Maintenance Expense — Baseline	$ 178	$ 170	$ 8	$ 592	$ 498	$ 94
Operating and Maintenance Expense — Regulatory Required Programs[(a)]	26	16	10	76	56	20
Total Operating and Maintenance Expense	$ 204	$ 186	$ 18	$ 668	$ 554	$ 114

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for the three and nine months ended September 30, 2014 compared to the same periods in 2013, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ 3	$ 7
Storm-related costs	17	101 [(a)]
Pension and non-pension postretirement benefits expense	(2)	(3)
Constellation merger and integration costs	(2)	(8)
Uncollectible Accounts Expense	(10)	(9)
Other	2	6
	8	94
Regulatory Required Programs		
Smart Meter	1	8
Energy Efficiency	8	12
Other	1	—
	10	20
Increase in operating and maintenance expense	$ 18	$ 114

(a) Total storm-related costs include approximately $85 million of incremental storm costs, including the February 5, 2014 ice storm and the significant July storms.

Depreciation and Amortization Expense

The increase in depreciation and amortization expense for the three and nine months ended September 30, 2014 compared to the same periods in 2013 was primarily due to ongoing capital expenditures.

Taxes Other Than Income

Taxes other than income for the three and nine months ended September 30, 2014 compared to the same period in 2013 remained relatively constant.

Interest Expense, Net

Interest expense, net for the three and nine months ended September 30, 2014 compared to the same periods in 2013 remained relatively constant.

Other, Net

Other, net for the three and nine months ended September 30, 2014 remained relatively level compared to the same period in 2013.

Effective Income Tax Rate

PECO's effective income tax rate was 23.6% and 27.6% for the three months ended September 30, 2014 and 2013, respectively.

The effective income tax rate was 24.3% and 29.5% for the nine months ended September 30, 2014 and 2013, respectively. See Note 11 — Income Taxes of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in effective income tax rate.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	% Change	Weather-Normal % Change
Retail Deliveries[a]								
Residential	3,551	3,781	(6.1)%	0.9%	10,200	10,134	0.7%	1.3%
Small commercial & industrial	2,096	2,142	(2.2)%	0.3%	6,098	6,111	(0.2)%	0.2%
Large commercial & industrial	4,086	4,207	(2.9)%	(1.4)%	11,604	11,637	(0.3)%	—%
Public authorities & electric railroads	241	219	10.0%	10.0%	722	712	1.4%	1.4%
Total Retail Deliveries	9,974	10,349	(3.6)%	—%	28,624	28,594	0.1%	0.5%

Number of Electric Customers	As of September 30, 2014	As of September 30, 2013
Residential	1,429,293	1,419,837
Small commercial & industrial	149,172	148,843
Large commercial & industrial	3,103	3,114
Public authorities & electric railroads	9,737	9,666
Total	1,591,305	1,581,460

Electric Revenue	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	% Change	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	% Change
Retail Sales[a]						
Residential	$ 413	$ 448	(7.8)%	$ 1,195	$ 1,197	(0.2)%
Small commercial & industrial	107	109	(1.8)%	319	324	(1.5)%
Large commercial & industrial	52	53	(1.9)%	169	173	(2.3)%
Public authorities & electric railroads	7	7	—%	23	23	—%
Total Retail	579	617	(6.2)%	1,706	1,717	(0.6)%
Other Revenue[b]	55	55	—%	165	163	1.4%
Total Electric Revenues	$ 634	$ 672	(5.7)%	$ 1,871	$ 1,880	(0.5)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.

(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.

PECO Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	% Change	Weather-Normal % Change
Retail Delivery								
Retail sales[(a)]	3,893	3,531	10.2%	10.4%	44,487	38,888	14.4%	2.2%
Transportation and other	5,750	6,041	(4.8)%	6.1%	20,124	20,880	(3.6)%	(1.6)%
Total Gas Deliveries	9,643	9,572	0.7%	7.8%	64,611	59,768	8.1%	0.9%

Number of Gas Customers	As of September 30, 2014	As of September 30, 2013
Residential	459,678	455,809
Commercial & industrial	42,008	41,591
Total Retail	501,686	497,400
Transportation	866	909
Total	502,552	498,309

Gas Revenue	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	% Change	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	% Change
Retail Sales						
Retail sales[(a)]	$ 54	$ 48	12.5%	$ 444	$ 386	15.1%
Transportation and other	5	8	(37.5)%	28	29	(3.4)%
Total Gas Revenues	$ 59	$ 56	5.4%	$ 472	$ 415	13.7%

(a) Reflects delivery volumes and revenues from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.

Results of Operations — BGE

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	Favorable (Unfavorable) Variance
Operating revenues	$ 697	$ 737	$ (40)	$2,404	$2,271	$ 133
Purchased power and fuel	297	346	49	1,094	1,059	(35)
Revenue net of purchased power and fuel[(a)]	400	391	9	1,310	1,212	98
Other operating expenses						
Operating and maintenance	165	146	(19)	541	450	(91)
Depreciation and amortization	78	78	—	275	252	(23)
Taxes other than income	55	53	(2)	168	162	(6)
Total other operating expenses	298	277	(21)	984	864	(120)
Operating income	102	114	(12)	326	348	(22)
Other income and (deductions)						
Interest expense, net	(26)	(29)	3	(81)	(94)	13
Other, net	4	4	—	14	13	1
Total other income and (deductions)	(22)	(25)	3	(67)	(81)	14
Income before income taxes	80	89	(9)	259	267	(8)
Income taxes	31	36	5	103	107	4
Net income	49	53	(4)	156	160	(4)
Preference stock dividends	3	3	—	10	10	—
Net income attributable to common shareholder	$ 46	$ 50	$ (4)	$ 146	$ 150	$ (4)

(a) BGE evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenue net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income attributable to common shareholders

Three Months Ended September 30, 2014, Compared to Three Months Ended September 30, 2013. BGE's net income attributable to common shareholders for the three months ended September 30, 2014, was lower than the same period in 2013, primarily due to an increase in operating and maintenance expense, partially offset by an increase in revenue net of purchased power and fuel expense as a result of the December 2013 electric and gas distribution rate order issued by the MDPSC.

Nine Months Ended September 30, 2014, Compared to Nine Months Ended September 30, 2013. BGE's net income attributable to common shareholders for the nine months ended September 30, 2014, was lower than the same period in 2013, primarily due to increases in operating and maintenance expense and depreciation expense, partially offset by an increase in revenue net of purchased power and fuel expense as a result of the 2013 electric and gas distribution rate orders issued by the MDPSC.

Operating Revenues, Purchased Power and Fuel Expense

There are certain drivers to operating revenue that are offset by their impact on purchased power expense and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively.

The number of customers electing to select a competitive electric generation supplier affects electric SOS revenues and purchased power expense. The number of customers electing to select a competitive natural gas supplier affects gas cost adjustment revenues and purchased natural gas expense. All BGE customers have the choice to purchase energy from a competitive electric generation supplier. This customer choice of electric generation suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to SOS. The number of retail customers purchasing electricity from a competitive electric generation supplier was 369,300 and 395,200 at September 30, 2014 and 2013, respectively, representing 30% and 32% of total retail customers at September 30, 2014 and 2013, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 60% of BGE's retail kWh sales for the three and nine months ended September 30, 2014, respectively, compared to 62% and 61% for the three and nine months ended September 30, 2013, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 161,500 and 167,700 at September 30, 2014 and 2013, respectively, representing 25% and 26% of total retail customers at September 30, 2014 and 2013, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 73% and 55% of BGE's retail mmcf sales for the three and nine months ended September 30, 2014, respectively, compared to 74% and 55% for the three and nine months ended September 30, 2013, respectively.

The changes in BGE's operating revenues net of purchased power and fuel expense for the three and nine months ended September 30, 2014, compared to the same period in 2013, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)			Nine Months Ended September 30, Increase (Decrease)		
	Electric	**Gas**	**Total**	**Electric**	**Gas**	**Total**
Distribution rate increase	$ 12	$ 1	$ 13	$ 47	$21	$ 68
Regulatory required programs	(3)	—	(3)	14	(1)	13
Commodity margin	4	1	5	6	9	15
Transmission revenues	2	—	2	10	—	10
Other	(7)	(1)	(8)	(10)	2	(8)
Total increase	$ 8	$ 1	$ 9	$ 67	$31	$ 98

Revenue Decoupling. The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenues from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

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Heating degree days are quantitative indices that reflect the demand for energy needed to heat a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE's service territory. The changes in heating degree days in BGE's service territory for the three and nine months ended September 30, 2014 compared to the same period in 2013 consisted of the following:

Heating and Cooling Degree-Days	2014	2013	Normal	% Change From 2013	% Change From Normal
Three Months Ended September 30,					
Heating Degree-Days	82	111	81	(26.1)%	1.2%
Cooling Degree-Days	484	567	596	(14.6)%	(18.8)%
Nine Months Ended September 30,					
Heating Degree-Days	3,439	3,054	2,981	12.6%	15.4%
Cooling Degree-Days	717	830	851	(13.6)%	(15.7)%

Distribution Rate Increase. The increase in distribution rates for the three and nine months ended September 30, 2014, compared to the same periods in 2013, was primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective in 2013 in accordance with the MDPSC approved electric and natural gas distribution rate case orders. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in revenues collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. Revenues related to regulatory required programs remained relatively consistent for the three months ended September 30, 2014 compared to the same period in 2013. The increase in revenues related to regulatory required programs for the nine months ended September 30, 2014 compared to the same period in 2013 was primarily due to the recovery of higher energy efficiency program costs.

Commodity Margin. The increase in commodity margin under BGE's market-based rate incentive mechanism for the three and nine months ended September 30, 2014, compared to the same periods in 2013 was primarily due to the higher gas margins earned by BGE due to the extreme cold weather during the first quarter under BGE's MBR mechanism and higher electric margins earned by BGE due to lower commodity prices in 2014. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenues. The increase in transmission rates for the three and nine months ended September 30, 2014, compared to the same periods in 2013, was primarily due to the impact of the new transmission rates charged to customers that became effective in June 2014. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other. Other revenues, which can vary from period to period, include miscellaneous revenues such as service application and late payment fees. Other revenues decreased during the three months ended September 30, 2014 compared to the same period in 2013, and remained relatively consistent for the nine months ended September 30, 2014 compared to the same period in 2013.

Operating and Maintenance Expense

The changes in operating and maintenance expense for the three and nine months ended September 30, 2014 compared to the same periods in 2013, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Labor, other benefits, contracting and materials	$ 13	$ 35
Pension and non-pension postretirement benefits expense	2	6
Storm-related costs	8	21
Uncollectible accounts expense	(3)	10
Other	(1)	19
Increase in operating and maintenance expense	$ 19	$ 91

Depreciation and Amortization

The increase in depreciation and amortization expense for the three and nine months ended September 30, 2014 compared to the same periods in 2013 was primarily due to higher amortization expense related to energy efficiency and demand response programs, which are fully offset in revenues above, and higher property, plant and equipment balances resulting from ongoing capital expenditures.

Taxes Other Than Income

The increase in taxes other than income for the three and nine months ended September 30, 2014 compared to the same periods in 2013 was primarily due to increased gross receipts tax as a result of higher revenues.

Interest Expense, Net

The decrease in interest expense, net for the three and nine months ended September 30, 2014 compared to the same periods in 2013 was primarily due to favorable interest rates in 2014 on long-term debt balances.

Effective Income Tax Rate

BGE's effective income tax rate was 38.8% and 40.4% for the three months ended September 30, 2014 and 2013, respectively, and 39.8% and 40.1% for the nine months ended September 30, 2014 and 2013, respectively. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rate.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	% Change	Weather-Normal % Change
Retail Deliveries[a]								
Residential	3,291	3,557	(7.5)%	n.m.	10,023	9,849	1.8%	n.m.
Small commercial & industrial	805	808	(0.4)%	n.m.	2,343	2,301	1.8%	n.m.
Large commercial & industrial	3,818	3,882	(1.6)%	n.m.	10,880	11,046	(1.5)%	n.m.
Public authorities & electric railroads	79	78	1.3%	n.m.	236	239	(1.3)%	n.m.
Total Electric Deliveries	7,993	8,325	(4.0)%	n.m.	23,482	23,435	0.2%	n.m.

Number of Electric Customers	As of September 30, 2014	As of September 30, 2013
Residential	1,123,644	1,119,209
Small commercial & industrial	112,580	112,988
Large commercial & industrial	11,707	11,634
Public authorities & electric railroads	290	293
Total	1,248,221	1,244,124

Electric Revenue	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	% Change	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	% Change
Retail Sales[a]						
Residential	$ 348	$ 390	(10.8)%	$ 1,077	$ 1,056	2.0%
Small commercial & industrial	72	72	—%	208	197	5.6%
Large commercial & industrial	134	116	15.5%	377	333	13.2%
Public authorities & electric railroads	8	8	—%	24	23	4.3%
Total Retail	562	586	(4.1)%	1,686	1,609	4.8%
Other Revenue	69	78	(11.5)%	207	203	2.0%
Total Electric Revenues	$ 631	$ 664	(5.0)%	$ 1,893	$ 1,812	4.5%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.

BGE Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended September 30, 2014	2013	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2014	2013	% Change	Weather-Normal % Change
Retail Deliveries[b]								
Retail sales	10,257	10,642	(3.6)%	n.m.	71,479	65,854	8.5%	n.m.
Transportation and other	304	933	(67.4)%	n.m.	7,508	8,128	(7.6)%	n.m.
Total Gas Deliveries	10,561	11,575	(8.8)%	n.m.	78,987	73,982	6.8%	n.m.

Number of Gas Customers	As of September 30, 2014	2013
Residential	610,750	612,065
Commercial & industrial	43,963	44,028
Total	654,713	656,093

Gas Revenue	Three Months Ended September 30, 2014	2013	% Change	Nine Months Ended September 30, 2014	2013	% Change
Retail Sales[b]						
Retail sales	$ 62	$ 66	(6.1)%	$ 439	$ 412	6.6%
Transportation and other[c]	4	7	(42.9)%	72	47	53.2%
Total Gas Revenues	$ 66	$ 73	(9.6)%	$ 511	$ 459	11.3%

(b) Reflects delivery volumes and revenues from customers purchasing natural gas directly from BGE and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. The cost of natural gas is charged to customers purchasing natural gas from BGE.

(c) Transportation and other gas revenue includes off-system revenue of 304 mmcfs ($2 million) and 933 mmcfs ($5 million) for the three months ended September 30, 2014 and 2013, respectively, and 7,508 mmcfs ($60 million) and 8,128 mmcfs ($37 million) for the nine months ended September 30, 2014 and 2013, respectively.

Liquidity and Capital Resources

Exelon's and Generation's current year activity presented below includes the activity of CENG from the integration date effective April 1, 2014 through September 30, 2014. All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, Exelon Corporate, Generation, ComEd, PECO and BGE have access to unsecured revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. Exelon Corporate, Generation, ComEd, PECO and BGE's revolving credit facilities expire in 2019. In addition, Generation has $0.5 billion in bilateral credit facilities. Generation's bilateral credit facilities have expirations in October 2014, January 2015, December 2015 and March 2016. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and issue letters of credit. See the "Credit Matters" section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO and BGE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 10 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

Cash Flows from Operating Activities

General

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

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

See Notes 5 — Regulatory Matters and 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. Certain provisions of the law were applied in 2012 while the others took effect in 2013. On August 8, 2014, this funding relief was extended for five years. The estimated impacts of the law are reflected in the projected pension contributions below.

Exelon expects to make qualified pension plan contributions of $308 million to its qualified pension plans in 2014, of which Generation, ComEd, PECO and BGE will contribute $160 million, $119 million, $11 million and $0 million, respectively. Exelon assumed sponsorship of the CENG pension and other postretirement benefit plans on July 14, 2014. CENG will fund the underfunded balances of the pension and other postretirement benefit plans measured at July 14, 2014. CENG's obligation for the qualified pension plans will be funded over a four year period beginning in 2014. CENG's obligation for the non-qualified pension and other postretirement benefit plans will be funded in June 2022 or upon the occurrence of certain specified events, such as EDF's disposition of a majority of its interest in CENG. Exelon's and Generation's expected qualified pension plan contributions above include $53 million and $51 million, respectively, related to the CENG plans for the period April 1, 2014 to December 31, 2014 (the period for which CENG is consolidated), of which CENG will contribute $43 million.

Exelon's non-qualified pension plans are not funded. Exelon expects to make non-qualified pension plan benefit payments of $18 million in 2014, of which Generation, ComEd, PECO and BGE will make payments of $9 million, $1 million, $0 million, and $1 million, respectively. Exelon's and Generation's expected non-qualified pension plan benefit payments above include $3 million related to the CENG plans for the period April 1, 2014 to December 31, 2014.

To the extent interest rates decline significantly or the pension plans do not earn the expected asset return rates, annual pension contribution requirements in future years could increase, especially in years 2017 and beyond. Additionally, the contributions above could change if Exelon changes its pension funding strategy.

Unlike qualified pension plans, other postretirement benefit plans are not subject to statutory minimum contribution requirements and certain plans are not funded. Exelon's management has historically considered several factors in determining the level of contributions to its funded other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued recovery). Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $290 million in 2014, of which Generation, ComEd, PECO and BGE expect to contribute $128 million, $121 million, $4 million, and $18 million, respectively. Exelon's and Generation's expected other postretirement benefit plan payments above include $5 million related to CENG plans for the period April 1, 2014 to December 31, 2014 and contemplate reductions related to recent plan design changes.

In October 2014, the Society of Actuaries issued a revised mortality table for use by actuaries, insurance companies, governments, benefit plan sponsors and others in setting assumptions regarding life expectancy in the United States for purposes of estimating pension and OPEB obligations, costs and required contribution amounts. The newly issued mortality tables indicate substantial life expectancy improvements since the last study published in 2000 (RP 2000). Adoption of the new mortality table would result in significantly increased future pension and OPEB plan obligations, costs and required contribution amounts for many plan sponsors, including Exelon. Exelon is currently evaluating the new table and potential impacts to the December 31, 2014 valuation and future expected pension and OPEB plan contributions. The IRS has indicated the RP 2000 should be used for ERISA funding calculations impacting qualified pension plans in 2014 and 2015, meaning the earliest a new table would be required for determining those funding requirements is January 1, 2016.

Tax Matters

The Registrants' future cash flows from operating activities may be affected by the following tax matters:

- Exelon, Generation, ComEd, PECO and BGE expect to receive tax refunds of approximately $360 million, $60 million, $320 million, $10 million and $20 million, respectively, between 2014 and 2015.
- State and local governments continue to face increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes or the imposition, extension or permanence of temporary tax levies.
- In the 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. The termination will result in a 2014 tax payment of approximately $285 million by Exelon and its subsidiaries in 2014, including approximately $155 million by ComEd. Exelon intends to fund its portion of the tax payment using a portion of the net early termination amount. ComEd intends to fund its portion of the tax payment using a combination of debt and equity contributions from Exelon to substantially maintain its existing capital structure. See Note 11 — Income Taxes of the Combined Notes to the Consolidated Financial Statements for additional information.
- Under the Taxpayer Relief Act of 2012, 50% bonus depreciation expired on December 31, 2013. In the second quarter of 2014, the Senate Finance Committee passed a two year extension of 50% bonus

depreciation for 2014 and 2015. Further, on July 11, 2014, the House of Representatives passed H.R. 4718 permanently extending 50% bonus depreciation beginning with the 2014 tax year. If ultimately enacted for 2014 and 2015, 50% bonus depreciation legislation would generate incremental cash of approximately $1,075 million, $500 million, $375 million, $100 million, and $100 million, for Exelon, Generation, ComEd, PECO, and BGE, respectively, primarily in 2015. The cash generated is an acceleration of tax benefits that Registrants would have received over the normal tax depreciable life of the qualifying property. Additionally, the extension of 50% bonus depreciation would result in a decrease to Generation's Domestic Production Activities Deduction, reducing cash tax benefits and increasing income tax expense by approximately $35 million and $25 million for 2014 and 2015, respectively. The potential extension of 50% bonus depreciation is not expected to result in a material impact on ComEd's, PECO's, or BGE's results of operations.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the nine months ended September 30, 2014 and 2013:

	Nine Months Ended September 30,		
	2014	2013	Variance
Net income	$ 1,725	$ 1,235	$ 490
Add (subtract):			
Non-cash operating activities[a]	4,200	3,094	1,106
Gain on consolidation of CENG	(268)	—	(268)
Pension and other postretirement benefit contributions	(516)	(360)	(156)
Income taxes	72	863	(791)
Changes in working capital and other noncurrent assets and liabilities[b]	(976)	(327)	(649)
Option premiums received (paid), net	21	(38)	59
Counterparty collateral posted, net	(615)	(73)	(542)
Net cash flows provided by operations	$ 3,643	$ 4,394	$ (751)

(a) Represents depreciation, amortization and accretion, impairment of long-lived assets, mark-to-market gains and losses on derivative transactions, deferred income taxes, provision for uncollectible accounts, pension and other postretirement benefit expense, equity in losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense and other non-cash charges.

(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

Cash flows provided by operations for the nine months ended September 30, 2014 and 2013 by Registrant were as follows:

	Nine Months Ended September 30,	
	2014	2013
Exelon	$ 3,643	$ 4,394
Generation	1,784	2,657
ComEd	849	850
PECO	504	620
BGE	625	433

Changes in Exelon's, Generation's, ComEd's, PECO's and BGE's cash flows provided by operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business. In addition, significant operating cash flow impacts for the Registrants for the nine months ended September 30, 2014 and 2013 were as follows:

Generation

- During the nine months ended September 30, 2014 and 2013, Generation had net payments of counterparty collateral of $634 million and $123 million, respectively. Net payments during the nine months ended September 30, 2014 and 2013 were primarily due to market conditions that resulted in changes to Generation's net mark-to-market position and initial margin requirements on the exchanges. Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. This collateral may be in various forms, such as cash, which may be obtained through the issuance of commercial paper, or letters of credit.
- During the nine months ended September 30, 2014 and 2013, Generation had net collections (payments) of approximately $21 million and $(38) million, respectively, related to purchases and sales of options. The level of option activity in a given period may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During the nine months ended September 30, 2014 and 2013, ComEd's payables for Generation energy purchases decreased by $(28) million and $(22) million, respectively, and payables to other energy suppliers for energy purchases increased by $58 million and $69 million, respectively.

PECO

- During the nine months ended September 30, 2014 and 2013, PECO's payables to Generation for energy purchases decreased by $(17) million and $(25) million, respectively, and payables to other electric and gas suppliers for energy purchases (decreased)/increased by $(12) million and $22 million, respectively.

BGE

- During the nine months ended September 30, 2014 and 2013, BGE's payables to Generation for energy purchases increased by $7 million and $9 million, respectively, and payables to other electric and gas suppliers for energy purchases decreased by $(27) million and $(25) million, respectively.

Cash Flows from Investing Activities

Cash flows used in investing activities for the nine months ended September 30, 2014 and 2013 by Registrant were as follows:

	Nine Months Ended September 30,	
	2014	2013
Exelon	$(3,376)	$(3,970)
Generation	(1,431)	(2,149)
ComEd	(1,148)	(1,042)
PECO	(452)	(368)
BGE	(480)	(409)

On February 26, 2014, UII and the CPS finalized an agreement to terminate the lease on the generating station located in Texas prior to its expiration date. As a result of the lease termination, UII received a net early termination amount of $335 million from CPS which is reflected in Exelon's cash flows from investing activities above. See Note 7 — Impairment of Long-Lived Assets for further information.

Generation

As a result of consolidating CENG during the second quarter of 2014, Generation recorded $129 million of cash from CENG, reflected in Generation's cash flows from investing activities above. See Note 6 — Investment in Constellation Energy Nuclear Group, LLC for further information.

Generation closed on the sale of its 67% equity interest in the 417 MW Safe Harbor Water Power Corporation hydroelectric facility on the Susquehanna River in Pennsylvania for a purchase price of approximately $615 million during the third quarter of 2014. The proceeds from the sale are reflected in Generation's cash flows from investing activities above. See Note 4 — Mergers, Acquisitions and Dispositions for further information.

During the third quarter of 2014, Generation established $65 million in restricted cash as part of the EGTP project financing which is reflected in Generation's cash flows from investing activities above. See Note 10 — Debt and Credit Agreements for more information.

Generation has entered into several agreements to acquire equity interests in privately held and development stage entities which develop energy-related technology. The agreements include a series of scheduled investment commitments, including in-kind services contributions, totaling approximately $182 million through 2018 to fund anticipated planned capital and operating needs of the associated companies.

Generation has also executed construction and services contracts to build new combined-cycle gas turbine units in Texas and Maryland and a new biomass-fueled cogeneration facility in Georgia. The total estimated expenditures for these projects are approximately $1.7 billion and achievement of commercial operations is expected in 2017 for all these projects.

Capital expenditures by Registrant for the nine months ended September 30, 2014 and 2013 and projected amounts for the full year 2014 are as follows:

	Projected Full Year 2014[(d)]	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Exelon	$ 5,925	$ 4,114	$ 3,887
Generation[(a)]	2,775	1,961	1,995
ComEd[(b)]	1,750	1,173	1,074
PECO	650	461	374
BGE	625	458	391
Other[(c)]	125	61	53

(a) Includes nuclear fuel.
(b) The projected capital expenditures include approximately $442 million of expected incremental spending pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten year period to modernize and storm-harden its distribution system and to implement smart grid technology.
(c) Other primarily consists of corporate operations and BSC.
(d) Total projected capital expenditures do not include adjustments for non-cash activity.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

In 2014, Exelon and its affiliates initiated a comprehensive project to ensure corporate-wide compliance with Version 5 of the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection Standards (CIP V.5) which will become effective on April 1, 2016. Generation, ComEd, PECO and BGE will be incurring incremental capital expenditures in 2014 through 2016 associated with the CIP V.5 compliance implementation project.

Generation

Approximately 36% and 10% of the projected 2014 capital expenditures at Generation are for the acquisition of nuclear fuel and investments in renewable energy generation, including Antelope Valley and wind construction costs, respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages).

ComEd, PECO and BGE

Approximately 84%, 77% and 88% of the projected 2014 capital expenditures at ComEd, PECO and BGE, respectively, are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA, and ComEd's, PECO's and BGE's construction commitments under PJM's RTEP. In addition to the capital expenditure for continuing projects, ComEd's total capital expenditures include smart grid/smart meter technology required under EIMA and for PECO and BGE, total capital expenditures related to their respective smart meter program and SGIG project.

In 2010, NERC provided guidance to transmission owners that recommends ComEd, PECO and BGE perform assessments of all their transmission lines. In compliance with this guidance, ComEd, PECO and BGE submitted their final bi-annual reports to NERC in January 2014. ComEd, PECO and BGE will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2014 capital expenditures above reflect capital spending in 2014 for remediation to be completed through 2017.

ComEd, PECO and BGE anticipate that they will fund their capital expenditures with internally generated funds and borrowings, including ComEd's capital expenditures associated with EIMA as further discussed in Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the nine months ended September 30, 2014 and 2013 by Registrant were as follows:

	Nine Months Ended September 30,	
	2014	2013
Exelon[(a)]	$ 887	$ (266)
Generation[(a)]	(300)	(251)
ComEd	307	82
PECO	77	(5)
BGE	(149)	(106)

(a) Includes $415 million of distributions to EDF.

Debt

See Note 10 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants' debt issuances and retirements.

Dividends

Cash dividend payments and distributions during the nine months ended September 30, 2014 and 2013 by Registrant were as follows:

	Nine Months Ended September 30,	
	2014	2013
Exelon[(a)]	$ 1,214	$ 981
Generation[(a)]	855	550
ComEd	230	165
PECO	240	249
BGE[(b)]	10	10

(a) Includes $415 million of distributions to EDF.
(b) Relates to dividends paid on BGE's preference stock.

First Quarter 2014 Dividend

On January 28, 2014, the Exelon Board of Directors declared a first quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on March 10, 2014, to shareholders of record of Exelon at the end of the day on February 14, 2014.

Second Quarter 2014 Dividend

On May 6, 2014, the Exelon Board of Directors declared a second quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on June 10, 2014, to shareholders of record of Exelon at the end of the day on May 16, 2014.

Third Quarter 2014 Dividend

On July 29, 2014, the Exelon Board of Directors declared a third quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on September 10, 2014 to shareholders of record of Exelon at the end of the day on August 15, 2014.

Fourth Quarter 2014 Dividend

On October 21, 2014, the Exelon Board of Directors declared a fourth quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on December 10, 2014 to shareholders of record of Exelon at the end of the day on November 14, 2014.

Short-Term Borrowings

During the nine months ended September 30, 2014, ComEd and BGE issued(repaid) $344 million and $(115) million of commercial paper, respectively, and Generation repaid $8 million in short-term notes payable. During the nine months ended September 30, 2013, ComEd issued $153 million of commercial paper, BGE issued $40 million of commercial paper and Generation issued $21 million in short-term notes payable.

Contributions from Parent/Member

During the nine months ended September 30, 2014, Generation, ComEd and PECO received $55 million, $168 million and $24 million from Parent (Exelon), respectively. During the nine months ended September 30, 2013, there were no contributions from Parent/Member (Exelon).

Distributions from Parent/Member

On April 1, 2014, Generation loaned $400 million to CENG, the proceeds of which were used to make a distribution to EDFI of $400 million. See Note 6 for additional information on the integration of CENG.

Other

For the nine months ended September 30, 2014, other financing activities primarily consisted of financing costs associated with the acquisition of PHI, other project financing and various debt issuance costs. See Notes 4, 10 and 16 for additional information.

Credit Matters

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include $8.5 billion in aggregate total commitments of which $7.5 billion was available as of September 30, 2014, and of which no financial institution has more than 8% of the aggregate commitments. Exelon, Generation, ComEd, PECO and BGE had access to the commercial paper market during the third quarter of 2014 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See Part I. Item 1A. Risk Factors of Exelon's 2013 Form 10-K for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of September 30, 2014, it would have been required to provide incremental collateral of $2.1 billion to meet collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within its current available credit facility capacities of $4.7 billion. If ComEd lost its investment grade credit rating as of September 30, 2014, it would have been required to provide incremental collateral of $17 million, which is well within its current available credit facility capacity of $470 million, which takes into account commercial paper borrowings as of September 30, 2014. If PECO lost its investment grade credit rating as of September 30, 2014, it would not be required to provide collateral pursuant to PJM's credit policy and would have been required to provide collateral of $25 million related to its natural gas procurement contracts, which, in the aggregate, are well within PECO's current available credit facility capacity of $599 million. If BGE lost its investment grade credit rating as of September 30, 2014, it would have been required to provide collateral of $2 million pursuant to PJM's credit policy and would have been required to provide collateral of $47 million related to its natural gas procurement contracts, which, in the aggregate, are well within BGE's current available credit facility capacity of $580 million.

Exelon Credit Facilities

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit. See Note 10 — Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for further information regarding the Registrants' credit facilities.

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at September 30, 2014:

Commercial Paper Programs

Commercial Paper Issuer	Maximum Program Size	Outstanding Commercial Paper at September 30, 2014	Average Interest Rate on Commercial Paper Borrowings for the nine months ended September 30, 2014
Exelon Corporate	$ 500	$ —	—%
Generation	5,600	—	0.32%
ComEd	1,000	528	0.32%
PECO	600	—	—%
BGE	600	20	0.27%

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of its commercial paper outstanding does not reduce available capacity under a Registrant's credit agreement, a Registrant does not issue commercial paper in an aggregate amount exceeding the available capacity under its credit agreement.

Credit Agreements

					Available Capacity at September 30, 2014	
Borrower	Facility Type	Aggregate Bank Commitment(a)	Facility Draws	Outstanding Letters of Credit	Actual	To Support Additional Commercial Paper
Exelon Corporate	Syndicated Revolver	$ 500	$ —	$ 6	$ 494	$ 494
Generation	Syndicated Revolver	5,300	—	557	4,743	4,743
Generation	Bilaterals	375	—	362	13	13
CENG	Bilaterals	100	—	—	100	—
ComEd	Syndicated Revolver	1,000	—	2	998	470
PECO	Syndicated Revolver	600	—	1	599	599
BGE	Syndicated Revolver	600	—	—	600	580

(a) Excludes $123 million of credit facility agreements arranged with minority and community banks at Generation, ComEd, PECO and BGE. These facilities expired on October 17, 2014 and were renewed at the same amount through October 16, 2015. These facilities are solely utilized to issue letters of credit. See Note 10 — Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for further information.

As of September 30, 2014, there were no borrowings under the Registrants' credit facilities.

On March 28, 2014, ComEd extended its unsecured revolving credit facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement expires on March 28, 2019. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to extend the facility for ComEd were not material.

On October 24, 2014, a $100 million bilateral CENG credit facility was amended and extended for an additional year. This facility has been utilized by CENG to fund working capital and capital projects and obtain letters of credit.

On May 30, 2014, each of Exelon Corporate, Generation, PECO and BGE extended the expiration date of its unsecured revolving credit facility with aggregate bank commitments of $500 million, $5.3 billion, $600 million, $600 million, respectively into May 2019, with the exception of a cumulative amount of $315 million which expires in August 2018. Costs incurred to extend the facilities were not material.

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's and BGE's credit facilities bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon each registrant's credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 7.5, 0.0 and 0.0 basis points, respectively, for prime based borrowings and 127.5, 127.5, 107.5, 90.0 and 100.0 basis points, respectively, for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of the borrower.

Each revolving credit agreement for Exelon, Generation, ComEd, PECO and BGE requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The following table summarizes the minimum thresholds reflected in the credit agreements for the nine months ended September 30, 2014:

	Exelon	Generation	ComEd	PECO	BGE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At September 30, 2014, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	10.23	11.92	6.14	7.65	8.66

An event of default under any Registrant's indebtedness will not constitute an event of default under any of the other Registrants' credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation will constitute an event of default under the Exelon Corporate credit facility.

Security Ratings

The Registrants' access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants' borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant's securities could increase fees and interest charges under that Registrant's credit agreements.

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, Exelon operates an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of September 30, 2014, are presented in the following table:

	Three Months Ended September 30, 2014		As of September 30, 2014
Contributed (borrowed)	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
Generation	$ —	$ 573	$ —
PECO	—	—	—
BSC	—	360	(273)
Exelon Corporate	780	N/A	273

Investments in Nuclear Decommissioning Trust Funds

Exelon, Generation and CENG maintain trust funds, as required by the NRC, to fund certain costs of decommissioning nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation's NDT fund investment policy. Generation's and CENG's investment policies establish limits on the concentration of holdings in any one company and also in any one industry. See Note 12 —Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC's minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements

The Registrants have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in May 2017. The ability of each Registrant to sell securities off the shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations

As of September 30, 2014, ComEd had $702 million available in long-term debt refinancing authority and $1.2 billion available in new money long-term debt financing authority from the ICC. As of September 30, 2014, PECO had $1.1 billion available in long-term debt financing authority from the PAPUC. As of September 30, 2014, BGE had $1.4 billion available in long-term financing authority from MDPSC.

As of September 30, 2014, ComEd, PECO and BGE had short-term financing authority from FERC, which expires on December 31, 2015, of $2.5 billion, $2.5 billion, and $0.7 billion, respectively. Generation currently has blanket financing authority from FERC, which was granted in connection with its market-based rate authority.

Contractual Obligations and Off-Balance Sheet Arrangements

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments triggered by future events. See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' commitments.

Generation, ComEd, PECO and BGE have obligations related to contracts for the purchase of power and fuel supplies, and ComEd, PECO and BGE have obligations related to their financing trusts. The power and fuel purchase contracts and the financing trusts have been considered for consolidation in the Registrants' respective financial statements pursuant to the authoritative guidance for VIEs. See Note 1 — Basis of Presentation of the Combined Notes to Consolidated Financial Statements for further information.

For an in-depth discussion of the Registrant's contractual obligations and off-balance sheet arrangements, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations and Off-Balance Sheet Arrangements" in the Exelon 2013 Form 10-K.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief enterprise risk officer and includes the chief executive officer, chief financial officer, chief commercial risk officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the Risk Oversight Committee of the Exelon Board of Directors on the scope of the risk management activities. The following discussion serves as an update to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of the Registrants' 2013 Annual Report on Form 10-K incorporated herein by reference.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel, and other commodities.

Generation

Normal Operations and Hedging Activities. Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of ComEd's, PECO's and BGE's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2014 through 2016.

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. Exelon's hedging program involves the hedging of commodity risk for Exelon's expected generation, typically on a ratable basis over a three-year period. This strategy has not changed as a result of recent and pending asset divestitures. As of September 30, 2014, the proportion of expected generation hedged is 98%-101%, 86%-89%, and 55%-58% for 2014, 2015, and 2016, 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 financial exposure through owned or contracted capacity and reflects the divestiture impact of Fore River, Quail Run, and West Valley; but does not reflect the divestiture impact of Generation's interest in Keystone and Conemaugh. See Note 4 – Mergers, Acquisitions and Dispositions and Note 21 – Subsequent Event for more detail regarding the divestitures. 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.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire non-trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on September 30, 2014 market conditions and hedged position would be an immaterial increase in pre-tax net income for 2014 and a decrease in pre-tax net income of approximately $120 million and

$470 million,respectively, for 2015 and 2016. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio.

Proprietary Trading Activities. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 3,006 GWhs and 8,129 GWhs for the three and nine months ended September 30, 2014, respectively, and 2,499 GWhs and 6,066 GWhs for the three and nine months ended September 30, 2013, respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Trading portfolio activity for the nine months ended September 30, 2014 resulted in pre-tax gains of $43 million due to net mark-to-market losses of $18 million and realized gains of $61 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, and a one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $0.3 million of exposure during the quarter. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation's total revenues net of purchased power and fuel expense from continuing operations for the nine months ended September 30, 2014 of $5,520 million.

Fuel Procurement. Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained primarily through long-term contracts for uranium concentrates, and long-term contracts for conversion services, enrichment services and fuel fabrication services. The supply markets for coal, natural gas, uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2014 through 2018 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial positions. See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding uranium and coal supply agreement matters.

ComEd

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC's December 18, 2013 Order approved the reduction of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved by the ICC in March 2014. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements in this report and Note 3 — Regulatory Matters of the Exelon 2013 Form 10-K for additional information regarding energy procurement and derivatives.

PECO

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 5 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements. PECO has certain full requirements contracts and block contracts which are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

PECO has also entered into derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge its long-term price risk in the natural gas market. PECO's hedging program for natural gas procurement has no direct impact on its financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

BGE

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE's MDPSC-approved SOS program. BGE's full requirements contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result, are accounted for on an accrual basis of accounting. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE's financial position. However, under BGE's market-based rates incentive mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers.

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities. The following detailed presentation of Exelon's, Generation's and ComEd's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon's, Generation's and ComEd's commodity mark-to-market net asset or liability balance sheet position from December 31, 2013 to September 30, 2014. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings as well as the settlements from OCI to earnings and changes in fair value for the cash flow hedging activities that are recorded in accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 9 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of September 30, 2014 and December 31, 2013.

	Generation	ComEd	Exelon
Total mark-to-market energy contract net assets (liabilities) at December 31, 2013[a]	$ 1,047	$ (193)	$ 854
Total change in fair value during 2014 of contracts recorded in results of operations	(495)	—	(495)
Reclassification to realized at settlement of contracts recorded in results of operations	—	—	—
Reclassification to realized at settlement from accumulated OCI	(130)	—	(130)
Changes in fair value — energy derivatives[b]	—	15	15
Changes in allocated collateral	603	—	603
Changes in net option premium paid/(received)	(21)	—	(21)
Option premium amortization	(92)	—	(92)
Other balance sheet reclassifications	(8)	—	(8)
Total mark-to-market energy contract net assets (liabilities) at September 30, 2014[a]	$ 904	$ (178)	$ 726

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of September 30, 2014, ComEd recorded a $178 million regulatory asset related to its mark-to-market derivative liabilities with unaffiliated suppliers. As of September 30, 2014, ComEd also recorded $19 million of decreases in fair value and $4 million of realized gains due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.

Fair Values. The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities), net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 8 — Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[a][b]							
Actively quoted prices (Level 1)	$ (18)	$ (33)	$ 14	$ (1)	$ —	$ —	$ (38)
Prices provided by external sources (Level 2)	167	293	59	(3)	—	(5)	511
Prices based on model or other valuation methods (Level 3)[c]	(24)	197	93	91	(10)	(94)	253
Total	$125	$457	$166	$87	$(10)	$ (99)	$ 726

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $459 million at September 30, 2014.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[a][b]							
Actively quoted prices (Level 1)	$ (18)	$ (33)	$ 14	$ (1)	$—	$ —	$ (38)
Prices provided by external sources (Level 2)	167	293	59	(3)	—	(5)	511
Prices based on model or other valuation methods (Level 3)	(18)	212	109	106	5	17	431
Total	$131	$472	$182	$102	$ 5	$ 12	$ 904

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $459 million at September 30, 2014.

ComEd

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and beyond	Total Fair Value
Prices based on model or other valuation methods[a]	$ (6)	$(15)	$(16)	$(15)	$(15)	$ (111)	$ (178)

(a) Represents ComEd's net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk, Collateral, and Contingent Related Features (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of September 30, 2014. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO and BGE of $11 million, $21 million and $34 million, respectively. See Note 25 — Related Party Transactions of the Exelon 2013 Form 10-K for additional information.

Rating as of September 30, 2014	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	$ 1,240	$ 88	$ 1,152	1	$ 423
Non-investment grade	23	7	16	—	—
No external ratings					
Internally rated — investment grade	302	—	302	1	180
Internally rated — non-investment grade	26	3	23	—	—
Total	$ 1,591	$ 98	$ 1,493	2	$ 603

Rating as of September 30, 2014	Maturity of Credit Risk Exposure			
	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 816	$ 355	$ 69	$ 1,240
Non-investment grade	16	7	—	23
No external ratings				
Internally rated — investment grade	218	87	(3)	302
Internally rated — non-investment grade	26	—	—	26
Total	$ 1,076	$ 449	$ 66	$ 1,591

Net Credit Exposure by Type of Counterparty	As of September 30, 2014
Financial institutions	$ 264
Investor-owned utilities, marketers, power producers	470
Energy cooperatives and municipalities	749
Other	10
Total	$ 1,493

(a) As of September 30, 2014, credit collateral held from counterparties where Generation had credit exposure included $94 million of cash and $4 million of letters of credit.

ComEd

There have been no significant changes or additions to ComEd's exposures to credit risk that are described in ITEM 1A. RISK FACTORS of Exelon's 2013 Annual Report on Form 10-K.

See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

PECO

There have been no significant changes or additions to PECO's exposures to credit risk as described in ITEM 1A. RISK FACTORS of Exelon's 2013 Annual Report on Form 10-K.

See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

BGE

There have been no significant changes or additions to BGE's exposures to credit risk as described in ITEM 1A. RISK FACTORS of Exelon's 2013 Annual Report on Form 10-K.

See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

Collateral (Exelon, Generation, ComEd, PECO and BGE)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, fossil fuel and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation sells output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial position. As market prices rise above contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See Note 10 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

As of September 30, 2014, Generation had cash collateral of $669 million posted and cash collateral held of $169 million for counterparties with derivative positions, of which $459 million in net cash collateral deposits and $2 million in net cash collateral receipts were offset against energy mark-to-market and interest rate and foreign exchange derivative assets and liabilities related to underlying energy contracts, respectively. As of September 30, 2014, $43 million of cash collateral posted was not offset against net derivative positions because it was not associated with energy-related derivatives, were associated with accrual positions, or as of the balance sheet date there were no positions to offset. See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of September 30, 2014, ComEd held approximately $2 million of collateral from suppliers in association with energy procurement contracts and held approximately $19 million in the form of cash and letters of credit for both annual and long-term renewable energy contracts. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements in this report and Note 3 — Regulatory Matters of the 2013 Exelon Form 10-K for additional information.

PECO

As of September 30, 2014, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

BGE

BGE is not required to post collateral under its electric supply contracts. As of September 30, 2014, BGE was not required to post collateral under its natural gas procurement contracts. However, BGE did hold approximately $16 million of collateral from suppliers for electric supply procurement contracts as of September 30, 2014. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

RTOs and ISOs (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd, PECO and BGE participate in all, or some, of the established, real-time energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

Exchange Traded Transactions (Exelon and Generation)

Generation enters into commodity transactions on NYMEX, ICE and the Nodal exchange. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk.

Long-Term Leases (Exelon)

Exelon's Consolidated Balance Sheet, as of September 30, 2014, included a $357 million net investment in coal-fired plants in Georgia subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of $685 million, less unearned income of $328 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessee does not exercise the fixed purchase options, Exelon has the ability to operate the stations and keep or market the power itself or require the lessee to arrange for a third party to bid on a service contract for a period following the lease term. Exelon will be subject to residual value risk if the lessee does not exercise the fixed purchase options.

This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. Lessee performance under the lease agreements is supported by collateral and credit enhancement measures. Management regularly evaluates the creditworthiness of Exelon's counterparties to these long-term leases. Exelon monitors the continuing credit quality of the credit enhancement party.

Exelon's Consolidated Balance Sheet, as of December 31, 2013, also included a net investment in a coal-fired plant in Texas subject to a long-term lease. In February 2014, Exelon and the City Public Service Board of San Antonio, Texas (CPS) finalized an agreement to terminate the leases prior to their expiration dates. As a result of the lease termination, Exelon received a net early termination amount of $335 million from CPS and wrote off the net investment in the CPS long-term lease of $336 million; resulting in a pre-tax loss of $1 million. See Note 11 — Income Taxes for the impact of the lease termination on income taxes.

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

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At September 30, 2014, Exelon and Generation had $1,600 million and $700 million of notional amounts of fixed-to-floating hedges outstanding, respectively, and $2,431 million and $781 million of notional amounts of floating-to-fixed hedges outstanding, respectively. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $7 million decrease in Exelon Consolidated pre-tax income for the nine months ended September 30, 2014. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. As of September 30, 2014, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $599 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

Item 4. Controls and Procedures

During the third quarter of 2014, each of Exelon's, Generation's, ComEd's, PECO's and BGE's management, including its principal executive officer and principal financial officer, evaluated its disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in its periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by all Registrants to ensure that (a) material information relating to that Registrant, including its consolidated subsidiaries, is accumulated and made known to Exelon's management, including its principal executive officer and principal financial officer, by other employees of that Registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of September 30, 2014, the principal executive officer and principal financial officer of each of Exelon, Generation, ComEd, PECO and BGE concluded that such Registrant's disclosure controls and procedures were effective to accomplish its objectives. All Registrants continually strive to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. There have been no changes in internal control over financial reporting that occurred during the third quarter of 2014 that have materially affected, or are reasonably likely to materially affect, any of Exelon's, Generation's, ComEd's, PECO's and BGE's internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1 Legal Proceedings

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see (a) ITEM 3. LEGAL PROCEEDINGS of Exelon's 2013 Form 10-K and (b) Notes 5 and 18 of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report. Such descriptions are incorporated herein by these references.

Item 1A Risk Factors

Risks Related to Exelon

In addition to the risk factors described in Part I, Item 1A. Risk Factors in Exelon's 2013 Form 10-K, Exelon faces the following additional risks.

Risks Related to the Pending Merger with PHI

Exelon and PHI may encounter difficulties in satisfying the conditions for the completion of the Merger and the Merger may not be completed within the expected time frame or at all.

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (1) the approval of the Merger by the holders of a majority of the outstanding shares of the PHI common stock, (2) the receipt of regulatory approvals required to consummate the Merger, (3) the expiration or termination of the applicable waiting period under the HSR Act and (4) other customary closing conditions, including (a) the accuracy of each party's representations and warranties (subject to customary materiality qualifiers) and (b) each party's compliance with its obligations and covenants contained in the Merger Agreement. In addition, the obligation of Exelon to consummate the Merger is subject to the required regulatory approvals not, individually or in the aggregate, imposing terms, conditions, obligations or commitments that constitute a burdensome condition (as defined in the Merger Agreement)

Satisfying the conditions to completion of the Merger may take longer, and could cost more, than Exelon expects. Any delay in completing the Merger or any additional conditions imposed in order to complete the Merger may materially adversely affect the synergies and other benefits that Exelon expects to achieve from the Merger and the integration of the companies' respective businesses.

In addition, conditions to the completion of the Merger may fail to be satisfied. Exelon or PHI may terminate the Merger Agreement if the Merger is not completed by July 29, 2015 except that, under certain circumstances, the date may be extended by Exelon or PHI to October 29, 2015.

The Merger is subject to the receipt of consent or approval from governmental entities that could delay the completion of the Merger or impose conditions that could have a material adverse effect on the combined company or that could cause abandonment of the Merger.

Completion of the Merger is conditioned upon the receipt of consents, orders, approvals or clearances, to the extent required, from the FERC, the FCC, the District of Columbia Public Service Commission, and the public utility commissions or similar entities in certain states in which the companies operate, including the Delaware Public Service Commission, MDPSC, the New Jersey Board of Public Utilities and the Virginia Department of Public Utilities. The Merger is also subject to review by the DOJ Antitrust Division, under the HSR Act, and the expiration or earlier termination of the waiting period (and any extension of the waiting period) applicable to the Merger is a condition to closing the Merger. As of September 30, 2014, Exelon and PHI have made all of the required regulatory filings and the Merger remains subject to the approval or review of each of the regulatory agencies mentioned above.

Exelon and PHI have proposed conditions for approval in some of the regulatory filings that have been made and may subsequently propose or agree to further conditions, even if such conditions could have an adverse effect on Exelon, PHI or the combined company.

Exelon cannot provide assurance that all required regulatory consents or approvals will be obtained or that these consents or approvals will not contain terms, conditions or restrictions that would be detrimental to the combined company after the completion of the Merger. The Merger Agreement generally permits Exelon to terminate the Merger Agreement if the final terms of any of the required regulatory consents or approvals include burdensome conditions (as defined in the Merger Agreement). Any substantial delay in obtaining satisfactory approvals, receipt of proceeds from asset divestitures in an amount substantially lower than anticipated or the imposition of any terms or conditions in connection with such approvals could cause a material reduction in the expected benefits of the Merger.

Failure to obtain regulatory approval may result in Exelon's payment of a reverse termination fee.

If the Merger Agreement is terminated under certain circumstances due to the failure to obtain regulatory approvals or the breach by Exelon of its obligations in respect of obtaining regulatory approvals, Exelon will be required to pay PHI a reverse termination fee of up to $180 million, by means of PHI redeeming the outstanding nonvoting preferred securities purchased by Exelon for no consideration other than the nominal par value of the stock.

Failure to complete the Merger could negatively affect the share price and the future business and financial results of Exelon.

Completion of the Merger is not assured and is subject to risks, including the risks that approval of the transaction by governmental agencies will not be obtained or that certain other closing conditions will not be satisfied. If the Merger is not completed, the ongoing businesses of Exelon may be adversely affected and Exelon will be subject to several risks, including:

- having to pay certain significant costs relating to the Merger without receiving the benefits of the Merger, including, in certain circumstances, a termination fee of up to $180 million payable by Exelon to PHI under some circumstances; and
- the share price of Exelon may decline if and to the extent that the current market prices reflect an assumption by the market that the Merger will be completed.

Exelon and PHI have and will incur significant transaction and Merger-related costs in connection with the Merger.

Exelon and PHI expect to incur a number of non-recurring costs associated with combining the operations of the two companies. Most of these costs will be transaction costs, including fees paid to financial and legal advisors related to the Merger and related financing arrangements, and employment-related costs, including change-in- control related payments made to certain PHI executives. In addition, if the closing of the Merger is materially delayed, Exelon may be required to pay financing costs without having realized any benefits from the Merger during the period of delay. Exelon will also incur transaction fees and costs related to formulating integration plans. Additional unanticipated costs may be incurred in the integration of the two companies' businesses. Although Exelon expects that the elimination of costs, as well as the realization of other efficiencies related to the integration of the businesses, will exceed incremental transaction and Merger-related costs over time, this net benefit may not be achieved in the near term, or at all.

Exelon may not realize the expected benefits of the Merger because of integration difficulties and other challenges.

The success of the PHI acquisition will depend, in part, on Exelon's ability to realize all or some of the anticipated benefits from integrating PHI's business with Exelon's existing businesses. The integration process may be complex, costly and time-consuming. The challenges associated with integrating the operations of PHI's business include, among others:

- delay in implementation of our business plan for the combined business;
- unanticipated issues or costs in integrating financial, information technology, communications and other systems;
- possible inconsistencies in standards, controls, procedures and policies, and compensation structures between PHI' s structure and our structure;
- unanticipated changes in applicable laws and regulations;
- difficulties in retention of key employees;
- operating risks inherent in PHI's business and our business; and
- unexpected regulatory requirements.

Exelon and PHI will be subject to various uncertainties while the Merger is pending that may adversely affect their ability to attract and retain key employees, and potentially affect the company's financial results.

Uncertainty about the effect of the Merger on employees, suppliers and customers may have an adverse effect on Exelon and/or PHI. These uncertainties may impair Exelon's and/or PHI's ability to attract, retain and motivate key personnel until the Merger is completed and for a period of time thereafter, as employees and prospective employees may experience uncertainty about their future roles with the combined company. In addition, current and prospective Exelon and PHI employees may determine that they do not desire to work for the combined company for a variety of possible reasons.

The Merger may divert attention of management at Exelon and PHI, which could detract from efforts to meet business goals.

The pursuit of the Merger and the preparation for the integration may place a burden on management and internal resources. Any significant diversion of management attention away from ongoing business concerns and any difficulties encountered in the transition and integration process could affect Exelon's and/or PHI's financial results. The process of integrating the operations of PHI may require a disproportionate amount of resources and management attention. Exelon's future operations and cash flows will depend to a significant degree upon Exelon's ability to operate PHI efficiently, achieve the strategic operating objectives for the business and realize cost savings and synergies. Exelon's management team may encounter unforeseen difficulties in managing the integration. In order to successfully integrate PHI, Exelon's management team will need to focus on realizing anticipated synergies and cost savings on a timely basis while maintaining the efficiency of operations. Any substantial diversion of management attention could affect Exelon's ability to achieve operational, financial and strategic objectives.

We are obligated to complete the Merger whether or not we have obtained the required financing.

Exelon intends to fund the cash consideration in the Merger using a combination of approximately $3.5 billion of debt, up to $1.0 billion in cash from asset sales, and the remainder through issuance of equity (including mandatory convertible securities). Exelon has executed a $2.0 billion equity offering of 57.5 million shares of common stock in connection with forward sales agreements and $1.2 billion of junior subordinated notes in the form of 23 million equity units. In addition, Exelon signed a 364-day $7.2 billion senior unsecured bridge credit facility to provide financing for the Merger pending the arrangement of permanent financing, which has subsequently been reduced to a $3.9 billion facility as a result of the equity issuances and applicable asset divestitures. The unsecured bridge credit facility is subject to various conditions contained in the agreement and the issuance of long-term debt and sales of assets to finance the Merger will be subject to future market conditions.

The combined company's assets, liabilities or results of operations could be adversely affected by unknown or unexpected events, conditions or actions that might occur at PHI prior to the closing of the Merger.

The PHI assets, liabilities, business, financial condition, cash flows, operating results and prospects to be acquired or assumed by Exelon by reason of the merger could be adversely affected before or after the Merger closing as a result of previously unknown events or conditions occurring or existing before the Merger closing. Adverse changes in PHI's business or operations could occur or arise as a result of actions by PHI, legal or regulatory developments including the emergence or unfavorable resolution of pre-acquisition loss contingencies, deteriorating general business, market, industry or economic conditions, and other factors both within and beyond the control of PHI. A significant decline in the value of PHI assets to be acquired by Exelon or a significant increase in PHI liabilities to be assumed by Exelon could adversely affect the combined company's future business, financial condition, cash flows, operating results and prospects.

Exelon may record goodwill that could become impaired and adversely affect its operating results.

In accordance with GAAP, the Merger will be accounted for as an acquisition of PHI common stock by Exelon and will follow the acquisition method of accounting for business combinations. The assets and liabilities of PHI will be consolidated with those of Exelon. The excess of the purchase price over the fair values of PHI's assets and liabilities, if any, will be recorded as goodwill.

The amount of goodwill, which could be material, will be allocated to the appropriate reporting units of the combined company. Exelon is required to assess goodwill for impairment at least annually by comparing the fair value of reporting units to the carrying value of those reporting units. To the extent the carrying value of any of those reporting units is greater than the fair value, a second step comparing the implied fair value of goodwill to the carrying amount would be required to determine if the goodwill is impaired. Such a potential impairment could result in a material charge that would have a material impact on Exelon's future operating results and consolidated balance sheet.

Legal proceedings in connection with the Merger, the outcomes of which are uncertain, could delay or prevent the completion of the Merger.

One of the conditions to the closing of the Merger is that no judgment (whether preliminary, temporary or permanent) or other order by any court or other governmental entity shall be in effect that restrains, enjoins or otherwise prohibits or makes illegal the consummation of the Merger.

PHI and its directors have been named as defendants in purported class action lawsuits filed on behalf of named plaintiffs and other public stockholders challenging the proposed Merger and seeking, among other things, to enjoin the defendants from consummating the Merger on the agreed-upon terms. Exelon has been named as a defendant in these lawsuits. Exelon has also been named in a federal court case with similar claims. In September 2014, the parties reached a proposed settlement which is subject to court approval. Final court approval of the proposed settlement is not expected to occur until the second quarter of 2015, at the earliest.

If a plaintiff in this or any other litigation that may be filed in the future is successful in obtaining an injunction prohibiting the parties from completing the Merger on the terms contemplated by the Merger Agreement, the injunction may prevent the completion of the Merger in the expected time frame or altogether. If completion of the Merger is prevented or delayed, it could result in substantial costs to Exelon. In addition, Exelon could incur significant costs in connection with the lawsuits, including costs associated with the indemnification of PHI's directors and officers.

Private parties who may believe they are adversely affected by the Merger and individual states may bring legal actions under the antitrust laws in certain circumstances or intervene in regulatory proceedings. Although Exelon and PHI believe the completion of the Merger will not conflict with any antitrust law, there can be no assurance that a challenge to the Merger on antitrust grounds will not be made or, if a challenge is made, what the result will be. Under the Merger Agreement, Exelon and PHI have agreed to use their reasonable best efforts to obtain all regulatory clearances necessary to complete the Merger as promptly as practicable. In addition, in order to complete the Merger, Exelon and PHI may be required to comply with conditions, terms, obligations or restrictions imposed by regulatory agencies and any such conditions, terms, obligations or restrictions may have the effect of delaying completion of the Merger, imposing additional material costs on or materially limiting Exelon's revenues after the completion of the Merger, or otherwise reducing the anticipated benefits from the Merger. In addition, any such conditions, terms, obligations or restrictions could result in the delay or abandonment of the Merger.

The Merger may be completed on terms different from those contained in the Merger Agreement.

Prior to the completion of the Merger, Exelon and PHI may, by their mutual agreement, amend or alter the terms of the Merger Agreement, including with respect to, among other things, the Merger consideration to be received by PHI stockholders or any covenants or agreements with respect to the parties' respective operations pending completion of the Merger. In addition, Exelon may choose to waive requirements of the Merger Agreement, including some conditions to closing of the Merger. Any such amendments, alterations or waivers may have negative consequences to Exelon.

Item 4 Mine Safety Disclosures

Exelon, Generation, ComEd, PECO and BGE

Not applicable to the Registrants.

Item 6 Exhibits

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
1.1	Underwriting Agreement dated September 8, 2014 among PECO, Mitsubishi UFJ Securities (USA), Inc., Mizuho Securities USA Inc. and RBS Securities Inc., as representatives of the several underwriters named therein. (File No. 000-16844, Form 8-K dated September 15, 2014, Exhibit 1.1)
4.1	One Hundred and Eleventh Supplemental Indenture dated as of September 1, 2014 from PECO to U.S. Bank National Association, as trustee. (File No. 000-16844, Form 8-K dated September 15, 2014, Exhibit 4.1)
10.1	Credit Agreement, dated as of September 18, 2014, among ExGen Texas Power, LLC, ExGen Texas Power Holdings, LLC, Wolf Hollow I Power, LLC, Colorado Bend I Power, LLC, Laporte Power, LLC, Handley Power, LLC and Mountain Creek Power, LLC, the lenders party thereto from time to time, Bank of America, N.A., as administrative agent and collateral agent, and Wilmington Trust, National Association, as depositary agent. (File No. 1-16169, Form 8-K dated September 18, 2014, Exhibit 10.1)

Exhibit No.	Description
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation
101.DEF	XBRL Taxonomy Extension Definition
101.LAB	XBRL Taxonomy Extension Labels
101.PRE	XBRL Taxonomy Extension Presentation

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2014 filed by the following officers for the following companies:

31-1	— Filed by Christopher M. Crane for Exelon Corporation
31-2	— Filed by Jonathan W. Thayer for Exelon Corporation
31-3	— Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
31-4	— Filed by Bryan P. Wright for Exelon Generation Company, LLC
31-5	— Filed by Anne R. Pramaggiore for Commonwealth Edison Company
31-6	— Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
31-7	— Filed by Craig L. Adams for PECO Energy Company
31-8	— Filed by Phillip S. Barnett for PECO Energy Company
31-9	— Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company
31-10	— Filed by David M. Vahos for Baltimore Gas and Electric Company

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes — Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2014 filed by the following officers for the following companies:

32-1	— Filed by Christopher M. Crane for Exelon Corporation
32-2	— Filed by Jonathan W. Thayer for Exelon Corporation
32-3	— Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
32-4	— Filed by Bryan P. Wright for Exelon Generation Company, LLC
32-5	— Filed by Anne R. Pramaggiore for Commonwealth Edison Company
32-6	— Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
32-7	— Filed by Craig L. Adams for PECO Energy Company
32-8	— Filed by Phillip S. Barnett for PECO Energy Company
32-9	— Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company
32-10	— Filed by David M. Vahos for Baltimore Gas and Electric Company

SIGNATURES

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON CORPORATION

/s/ CHRISTOPHER M. CRANE	/s/ JONATHAN W. THAYER
Christopher M. Crane President and Chief Executive Officer (Principal Executive Officer)	Jonathan W. Thayer Senior Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ DUANE M. DESPARTE	
Duane M. DesParte Senior Vice President and Corporate Controller (Principal Accounting Officer)	

October 29, 2014

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON GENERATION COMPANY, LLC

/s/ KENNETH W. CORNEW	/s/ BRYAN P. WRIGHT
Kenneth W. Cornew President and Chief Executive Officer (Principal Executive Officer)	Bryan P. Wright Chief Financial Officer (Principal Financial Officer)
/s/ ROBERT M. AIKEN	
Robert M. Aiken Chief Accounting Officer (Principal Accounting Officer)	

October 29, 2014

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Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

COMMONWEALTH EDISON COMPANY

/s/ ANNE R. PRAMAGGIORE	/s/ JOSEPH R. TRPIK, JR.
Anne R. Pramaggiore President and Chief Executive Officer (Principal Executive Officer)	Joseph R. Trpik, Jr. Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ GERALD J. KOZEL	
Gerald J. Kozel Vice President and Controller (Principal Accounting Officer)	

October 29, 2014

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PECO ENERGY COMPANY

/s/ CRAIG L. ADAMS	/s/ PHILLIP S. BARNETT
Craig L. Adams President and Chief Executive Officer (Principal Executive Officer)	Phillip S. Barnett Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ SCOTT A. BAILEY	
Scott A. Bailey Vice President and Controller (Principal Accounting Officer)	

October 29, 2014

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ CALVIN G. BUTLER, JR.	/s/ DAVID M. VAHOS
Calvin G. Butler, Jr. Chief Executive Officer (Principal Executive Officer)	David M. Vahos Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ MATTHEW N. BAUER	
Matthew N. Bauer Vice President and Controller (Principal Accounting Officer)	

October 29, 2014

Exhibit 31-1

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Christopher M. Crane, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

/s/ CHRISTOPHER M. CRANE
President and Chief Executive Officer
(Principal Executive Officer)

Date: October 29, 2014

Exhibit 31-2

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Jonathan W. Thayer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JONATHAN W. THAYER
Senior Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

Date: October 29, 2014

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. Cornew, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

/s/ KENNETH W. CORNEW
President and Chief Executive Officer
(Principal Executive Officer)

Date: October 29, 2014

Exhibit 31-4

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Bryan P. Wright, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ BRYAN P. WRIGHT
Chief Financial Officer
(Principal Financial Officer)

Date: October 29, 2014

Exhibit 31-5

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Anne R. Pramaggiore, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ ANNE R. PRAMAGGIORE
President and Chief Executive Officer
(Principal Executive Officer)

Date: October 29, 2014

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Joseph R. Trpik, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JOSEPH R. TRPIK, JR.
Senior Vice President, Chief Financial Officer
and Treasurer
(Principal Financial Officer)

Date: October 29, 2014

Exhibit 31-7

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Craig L. Adams, certify that:

1. I have reviewed this quarterly report on Form 10-Q of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ CRAIG L. ADAMS

President and Chief Executive Officer
(Principal Executive Officer)

Date: October 29, 2014

Exhibit 31-8

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Phillip S. Barnett, certify that:

1. I have reviewed this quarterly report on Form 10-Q of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ PHILLIP S. BARNETT

Senior Vice President, Chief Financial Officer
and Treasurer
(Principal Financial Officer)

Date: October 29, 2014

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Calvin G. Butler, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Baltimore Gas and Electric Company;

2. I have reviewed this quarterly report on Form 10-Q of Baltimore Gas and Electric Company;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

/s/ CALVIN G. BUTLER, JR.
Chief Executive Officer
(Principal Executive Officer)

Date: October 29, 2014

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Vahos, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

/s/ DAVID M. VAHOS

Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: October 29, 2014

Exhibit 32-1

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Corporation for the quarterly period ended September 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/s/ CHRISTOPHER M. CRANE
Christopher M. Crane
President and Chief Executive Officer

Date: October 29, 2014

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Corporation for the quarterly period ended September 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/s/ JONATHAN W. THAYER

Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer

Date: October 29, 2014

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Generation Company, LLC for the quarterly period ended September 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/s/ KENNETH W. CORNEW

Kenneth W. Cornew
President and Chief Executive Officer

Date: October 29, 2014

Exhibit 32-4

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Generation Company, LLC for the quarterly period ended September 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/s/ BRYAN P. WRIGHT
Bryan P. Wright
Chief Financial Officer

Date: October 29, 2014

Exhibit 32-5

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended September 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/s/ ANNE R. PRAMAGGIORE
Anne R. Pramaggiore
President and Chief Executive Officer

Date: October 29, 2014

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended September 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/s/ JOSEPH R. TRPIK, JR.
Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Date: October 29, 2014

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of PECO Energy Company for the quarterly period ended September 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/s/ CRAIG L. ADAMS

Craig L. Adams

President and Chief Executive Officer

Date: October 29, 2014

Exhibit 32-8

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of PECO Energy Company for the quarterly period ended September 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/s/ PHILLIP S. BARNETT

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer

Date: October 29, 2014

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Baltimore Gas and Electric Company for the quarterly period ended September 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15 (d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ CALVIN G. BUTLER, JR.
Calvin G. Butler, Jr.
Chief Executive Officer

Date: October 29, 2014

Exhibit 32-10

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Baltimore Gas and Electric Company for the quarterly period ended September 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15 (d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ DAVID M. VAHOS

David M. Vahos

Vice President, Chief Financial Officer and Treasurer

Date: October 29, 2014