UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the Quarterly Period Ended June 30, 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 x 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 x No ¨

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

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

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

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

Exelon Corporation Common Stock, without par value	859,197,443
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,914
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

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
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFL	Compact Fluorescent Light

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Other Terms and Abbreviations	
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
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
ISO-NE	ISO New England Inc.
ISO-NY	ISO New York
kV	Kilovolt
kW	Kilowatt

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
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
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

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
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

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FILING FORMAT

This combined Form 10-Q is being filed separately by the Registrants. Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

FORWARD-LOOKING STATEMENTS

This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company and Baltimore Gas and Electric Company (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.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions, except per share data)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Operating revenues	$ 6,024	$ 6,141	$ 13,261	$ 12,223
Operating expenses				
Purchased power and fuel	2,346	2,132	6,352	4,795
Purchased power and fuel from affiliates	66	287	400	605
Operating and maintenance	2,166	1,892	4,024	3,656
Depreciation and amortization	590	533	1,154	1,076
Taxes other than income	288	271	580	548
Total operating expenses	5,456	5,115	12,510	10,680
Equity in losses of unconsolidated affiliates		(21)	(20)	(30)
Gain on consolidation of CENG	261		261	
Operating income	829	1,005	992	1,513
Other income and (deductions)				
Interest expense	(228)	(246)	(445)	(863)
Interest expense to affiliates, net	(10)	(6)	(20)	(13)
Other, net	243	(17)	348	155
Total other income and (deductions)	5	(269)	(117)	(721)
Income before income taxes	834	736	875	792
Income taxes	277	239	224	294
Net income	557	497	651	498
Net income attributable to non-controlling interests, preferred security dividends and redemption and preference stock dividends	35	7	39	12
Net income attributable to common shareholders	522	490	612	486
Comprehensive income, net of income taxes				
Net income	557	497	651	498
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(6)		(6)	1
Actuarial loss reclassified to periodic cost	38	50	72	100
Pension and non-pension postretirement benefit plans valuation adjustment	258	2	246	77
Deferred compensation unit valuation adjustment		10		10
Unrealized loss on cash flow hedges	(48)	(65)	(73)	(123)
Unrealized gain on equity investments		8	11	36
Unrealized gain (loss) on foreign currency translation	4	(5)	(1)	(6)
Unrealized gain (loss) on marketable securities	1		1	(1)
Reversal of CENG equity method AOCI	(116)		(116)	

Other comprehensive income	131		134	94
Comprehensive income	$ 688	$ 497	$ 785	$ 592
Average shares of common stock outstanding:				
Basic	860	856	860	856
Diluted	864	860	863	859
Earnings per average common share:				
Basic	$ 0.61	$ 0.57	$ 0.71	$ 0.57
Diluted	$ 0.60	$ 0.57	$ 0.71	$ 0.57
Dividends per common share	$ 0.31	$ 0.31	$ 0.62	$ 0.84

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)	**Six Months Ended June 30, 2014**	**2013**
Cash flows from operating activities		
Net income	$ 651	$ 498
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	1,925	1,972
Gain on consolidation of CENG	(268)	
Deferred income taxes and amortization of investment tax credits	133	(468)
Net fair value changes related to derivatives	751	(28)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(168)	(27)
Other non-cash operating activities	567	576
Changes in assets and liabilities:		
Accounts receivable	48	131
Inventories	(150)	(18)
Accounts payable, accrued expenses and other current liabilities	(358)	(583)
Option premiums received (paid), net	21	(10)
Counterparty collateral posted, net	(606)	(259)
Income taxes	(16)	705
Pension and non-pension postretirement benefit contributions	(499)	(284)
Other assets and liabilities	(280)	133
Net cash flows provided by operating activities	1,751	2,338
Cash flows from investing activities		
Capital expenditures	(2,501)	(2,518)
Proceeds from termination of direct financing lease investment	335	
Proceeds from nuclear decommissioning trust fund sales	4,219	1,448
Investment in nuclear decommissioning trust funds	(4,238)	(1,565)
Acquisition of business	(66)	(3)
Proceeds from sale of long-lived assets	32	4
Cash consolidated from CENG	129	
Change in restricted cash	(40)	22
Other investing activities	(57)	63
Net cash flows used in investing activities	(2,187)	(2,549)
Cash flows from financing activities		
Changes in short-term borrowings	293	662
Issuance of long-term debt	2,100	509
Retirement of long-term debt	(1,191)	(616)
Redemption of preferred securities		(93)
Distributions to non-controlling interest of consolidated VIE	(415)	
Dividends paid on common stock	(533)	(716)
Proceeds from employee stock plans	18	32
Other financing activities	(83)	(62)
Net cash flows provided by (used in) financing activities	189	(284)

Decrease in cash and cash equivalents	(247)	(495)
Cash and cash equivalents at beginning of period	1,609	1,486
Cash and cash equivalents at end of period	$ 1,362	$ 991

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,362	$ 1,609
Restricted cash and investments	207	167
Accounts receivable, net		
Customer	2,973	2,981
Other	1,005	1,175
Mark-to-market derivative assets	629	727
Unamortized energy contract assets	264	374
Inventories, net		
Fossil fuel	409	276
Materials and supplies	1,041	829
Deferred income taxes	426	573
Regulatory assets	732	760
Other	775	666
Total current assets	9,823	10,137
Property, plant and equipment, net	51,747	47,330
Deferred debits and other assets		
Regulatory assets	5,545	5,910
Nuclear decommissioning trust funds	10,437	8,071
Investments	839	1,165
Investments in affiliates	22	22
Investment in CENG		1,925
Goodwill	2,674	2,625
Mark-to-market derivative assets	482	607
Unamortized energy contracts assets	593	710
Pledged assets for Zion Station decommissioning	402	458
Other	1,092	964
Total deferred debits and other assets	22,086	22,457
Total assets[(a)]	$ 83,656	$ 79,924

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 621	$ 341
Long-term debt due within one year	2,047	1,509
Accounts payable	2,633	2,484
Accrued expenses	1,382	1,633
Payables to affiliates	38	116
Deferred income taxes	17	40
Regulatory liabilities	368	327
Mark-to-market derivative liabilities	228	159
Unamortized energy contract liabilities	239	261
Other	994	858
Total current liabilities	8,567	7,728
Long-term debt	18,133	17,623
Long-term debt to financing trusts	648	648
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	13,192	12,905
Asset retirement obligations	7,054	5,194
Pension obligations	1,804	1,876
Non-pension postretirement benefit obligations	1,419	2,190
Spent nuclear fuel obligation	1,021	1,021
Regulatory liabilities	4,670	4,388
Mark-to-market derivative liabilities	262	300
Unamortized energy contract liabilities	260	266
Payable for Zion Station decommissioning	264	305
Other	2,133	2,540
Total deferred credits and other liabilities	32,079	30,985
Total liabilities[a]	59,427	56,984
Commitments and contingencies		
Shareholders equity		
Common stock (No par value, 2,000 shares authorized, 894 shares and 857 shares outstanding at June 30, 2014 and December 31, 2013, respectively)	16,651	16,741
Treasury stock, at cost (35 shares at June 30, 2014 and December 31, 2013, respectively)	(2,327)	(2,327)
Retained earnings	10,435	10,358
Accumulated other comprehensive loss, net	(1,906)	(2,040)
Total shareholders equity	22,853	22,732
BGE preference stock not subject to mandatory redemption	193	193
Noncontrolling interest	1,183	15

Total equity	24,229	22,940
Total liabilities and shareholders equity	$ 83,656	$ 79,924

(a) Exelon s consolidated assets include $7,765 million and $1,755 million at June 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 $3,111 million and $658 million at June 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	Non-controlling 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				612		33	6	651
Long-term incentive plan activity	1,408	32						32
Employee stock purchase plan issuances	499	14						14
Allocation of tax benefit from member		(5)						(5)
Acquisition of non-controlling interest						2		2
Common stock dividends				(535)				(535)
Preferred and preference stock dividends							(6)	(6)
Fair value of financing contract payments		(131)						(131)
Non-controlling interest established upon consolidation of CENG						1,548		1,548
Consolidated VIE dividend to non-controlling 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 $(159)					250			250
Balance, June 30, 2014	893,941	$ 16,651	$ (2,327)	$ 10,435	$ (1,906)	$ 1,183	$ 193	$ 24,229

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Operating revenues				
Operating revenues	$ 3,588	$ 3,718	$ 7,644	$ 6,859
Operating revenues from affiliates	201	352	535	744
Total operating revenues	3,789	4,070	8,179	7,603
Operating expenses				
Purchased power and fuel	1,766	1,656	4,774	3,503
Purchased power and fuel from affiliates	69	290	417	611
Operating and maintenance	1,255	1,041	2,194	2,007
Operating and maintenance from affiliates	158	148	305	295
Depreciation and amortization	254	210	466	424
Taxes other than income	118	101	223	194
Total operating expenses	3,620	3,446	8,379	7,034
Equity in losses of unconsolidated affiliates	(1)	(21)	(20)	(30)
Gain on consolidation of CENG	261		261	
Operating income	429	603	41	539
Other income and (deductions)				
Interest expense	(74)	(77)	(147)	(142)
Interest expense to affiliates, net	(12)	(16)	(25)	(34)
Other, net	228	(33)	318	95
Total other income and (deductions)	142	(126)	146	(81)
Income before income taxes	571	477	187	458
Income taxes (benefit)	199	149	(1)	148
Net income	372	328	188	310
Net income (loss) attributable to noncontrolling interests	32	(2)	33	(1)
Net income attributable to membership interest	340	330	155	311
Comprehensive income, net of income taxes				
Net income	372	328	188	310
Other comprehensive income (loss), net of income taxes				
Unrealized loss on cash flow hedges	(45)	(137)	(70)	(267)
Unrealized gain on equity investments		8	11	36
Unrealized gain (loss) on foreign currency translation	4	(5)	(1)	(6)
Unrealized gain (loss) on marketable securities	2		(1)	(1)
Reversal of CENG equity method AOCI	(116)		(116)	

Other comprehensive loss	(155)	(134)	(177)	(238)
Comprehensive income	$ 217	$ 194	$ 11	$ 72

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Six Months Ended June 30, 2014	2013
Cash flows from operating activities		
Net income	$ 188	$ 310
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	1,242	1,358
Gain on consolidation of CENG	(268)	
Deferred income taxes and amortization of investment tax credits	(15)	(44)
Net fair value changes related to derivatives	760	(21)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(168)	(27)
Other non-cash operating activities	209	315
Changes in assets and liabilities:		
Accounts receivable	63	88
Receivables from and payables to affiliates, net	(20)	(29)
Inventories	(170)	(38)
Accounts payable, accrued expenses and other current liabilities	(273)	(426)
Option premiums received (paid), net	21	(10)
Counterparty collateral paid, net	(633)	(303)
Income taxes	72	265
Pension and non-pension postretirement benefit contributions	(210)	(120)
Other assets and liabilities	(56)	(168)
Net cash flows provided by operating activities	742	1,150
Cash flows from investing activities		
Capital expenditures	(1,103)	(1,277)
Proceeds from nuclear decommissioning trust fund sales	4,219	1,448
Investment in nuclear decommissioning trust funds	(4,238)	(1,565)
Acquisition of business	(66)	
Proceeds from sale of long-lived assets	32	
Change in restricted cash	(17)	(11)
Changes in Exelon intercompany money pool	44	
Cash consolidated from CENG	129	
Other investing activities	(14)	27
Net cash flows used in investing activities	(1,014)	(1,378)
Cash flows from financing activities		
Change in short-term borrowings	46	288
Issuance of long-term debt	300	209
Retirement of long-term debt	(538)	(458)
Changes in Exelon intercompany money pool	190	263
Distribution to member	(235)	(474)
Distributions to non-controlling interest of consolidated VIE	(415)	
Other financing activities	(29)	(49)
Net cash flows used in financing activities	(681)	(221)

Decrease in cash and cash equivalents	(953)	(449)
Cash and cash equivalents at beginning of period	1,258	671
Cash and cash equivalents at end of period	$ 305	$ 222

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)	June 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 305	$ 1,258
Restricted cash and cash equivalents	88	71
Accounts receivable, net		
Customer	1,733	1,689
Other	441	353
Mark-to-market derivative assets	629	727
Receivables from affiliates	67	108
Receivable from Exelon intercompany pool		44
Unamortized energy contract assets	264	374
Inventories, net		
Fossil fuel	328	164
Materials and supplies	872	671
Deferred income taxes	476	475
Other	524	505
Total current assets	5,727	6,439
Property, plant and equipment, net	23,743	20,111
Deferred debits and other assets		
Nuclear decommissioning trust funds	10,437	8,071
Investments	432	400
Investment in CENG		1,925
Goodwill, net	49	
Mark-to-market derivative assets	464	600
Prepaid pension asset	1,888	1,873
Pledged assets for Zion Station decommissioning	402	458
Unamortized energy contract assets	593	710
Other	687	645
Total deferred debits and other assets	14,952	14,682
Total assets[(a)]	$ 44,422	$ 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)	June 30, 2014 (Unaudited)	December 31, 2013
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 53	$ 22
Long-term debt due within one year	52	561
Long-term debt to affiliates due within one year	563	
Accounts payable	1,508	1,322
Accrued expenses	819	976
Payables to affiliates	108	181
Borrowings from Exelon intercompany money pool	190	
Deferred income taxes	1	25
Mark-to-market derivative liabilities	215	142
Unamortized energy contract liabilities	233	249
Other	473	389
Total current liabilities	4,215	3,867
Long-term debt	5,944	5,645
Long-term debt to affiliate	948	1,523
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	6,334	6,295
Asset retirement obligations	6,907	5,047
Pension obligations	125	
Non-pension postretirement benefit obligations	941	850
Spent nuclear fuel obligation	1,021	1,021
Payables to affiliates	2,917	2,740
Mark-to-market derivative liabilities	135	120
Unamortized energy contract liabilities	260	266
Payable for Zion Station decommissioning	264	305
Other	761	811
Total deferred credits and other liabilities	19,665	17,455
Total liabilities[a]	30,772	28,490
Commitments and contingencies		
Equity		
Member s equity		
Membership interest	8,895	8,898
Undistributed earnings	3,533	3,613
Accumulated other comprehensive income, net	37	214
Total member s equity	12,465	12,725
Noncontrolling interest	1,185	17
Total equity	13,650	12,742

Total liabilities and equity	$ 44,422	$ 41,232

(a) Generation s consolidated assets include $7,711 million and $1,695 million at June 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 $2,855 million and $362 million at June 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

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(Unaudited)

	Member s Equity				
(In millions)	**Membership Interest**	**Undistributed Earnings**	**Accumulated Other Comprehensive Income, net**	**Non-controlling Interest**	**Total Equity**
Balance, December 31, 2013	$ 8,898	$ 3,613	$ 214	$ 17	$ 12,742
Net income		155		33	188
Acquisition of non-controlling interest				2	2
Allocation of tax benefit from member	(3)				(3)
Distribution to member		(235)			(235)
Non-controlling interest established upon consolidation of CENG				1,548	1,548
Consolidated VIE dividend to non-controlling 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 $35			(61)		(61)
Balance, June 30, 2014	$ 8,895	$ 3,533	$ 37	$ 1,185	$ 13,650

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Operating revenues				
Operating revenues	$ 1,128	$ 1,080	$ 2,261	$ 2,238
Operating revenues from affiliates			1	1
Total operating revenues	1,128	1,080	2,262	2,239
Operating expenses				
Purchased power	204	127	416	364
Purchased power from affiliate	65	121	173	266
Operating and maintenance	316	319	603	611
Operating and maintenance from affiliate	39	40	78	76
Depreciation and amortization	174	170	347	337
Taxes other than income	72	71	149	145
Total operating expenses	870	848	1,766	1,799
Operating income	258	232	496	440
Other income and (deductions)				
Interest expense	(76)	(72)	(153)	(422)
Interest expense to affiliates, net	(4)	(4)	(7)	(7)
Other, net	5	6	10	11
Total other income and (deductions)	(75)	(70)	(150)	(418)
Income before income taxes	183	162	346	22
Income taxes	72	66	137	8
Net income	111	96	209	14
Comprehensive income	$ 111	$ 96	$ 209	$ 14

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six Months Ended June 30,	
(In millions)	**2014**	**2013**
Cash flows from operating activities		
Net income	$ 209	$ 14
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	347	337
Deferred income taxes and amortization of investment tax credits	63	(226)
Other non-cash operating activities	99	39
Changes in assets and liabilities:		
Accounts receivable	(83)	18
Receivables from and payables to affiliates, net	(46)	(26)
Inventories	(4)	(11)
Accounts payable, accrued expenses and other current liabilities	27	20
Income taxes	5	240
Pension and non-pension postretirement benefit contributions	(236)	(119)
Other assets and liabilities	48	217
Net cash flows provided by operating activities	429	503
Cash flows from investing activities		
Capital expenditures	(747)	(711)
Proceeds from sales of investments	7	4
Purchases of investments	(3)	(3)
Change in restricted cash	(2)	(3)
Other investing activities	14	20
Net cash flows used in investing activities	(731)	(693)
Cash flows from financing activities		
Changes in short-term borrowings	314	374
Issuance of long-term debt	650	
Retirement of long-term debt	(617)	(125)
Contributions from parent	112	
Dividends paid on common stock	(153)	(110)
Other financing activities	(2)	
Net cash flows provided by financing activities	304	139
Increase (Decrease) in cash and cash equivalents	2	(51)
Cash and cash equivalents at beginning of period	36	144
Cash and cash equivalents at end of period	$ 38	$ 93

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 38	$ 36
Restricted cash	4	2
Accounts receivable, net		
Customer	516	451
Other	428	584
Inventories, net	112	109
Regulatory assets	304	329
Other	32	29
Total current assets	1,434	1,540
Property, plant and equipment, net	15,121	14,666
Deferred debits and other assets		
Regulatory assets	850	933
Investments	1	5
Investments in affiliates	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,606	2,469
Prepaid pension asset	1,626	1,583
Other	275	291
Total deferred debits and other assets	7,989	7,912
Total assets	$ 24,544	$ 24,118

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 498	$ 184
Long-term debt due within one year	260	617
Accounts payable	505	449
Accrued expenses	274	307
Payables to affiliates	37	83
Customer deposits	130	133
Regulatory liabilities	164	170
Deferred income taxes	117	16
Mark-to-market derivative liability	13	17
Other	82	72
Total current liabilities	2,080	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	4,080	4,116
Asset retirement obligations	100	99
Non-pension postretirement benefits obligations	284	381
Regulatory liabilities	3,686	3,512
Mark-to-market derivative liability	121	176
Other	841	994
Total deferred credits and other liabilities	9,112	9,278
Total liabilities	16,846	16,590
Commitments and contingencies		
Shareholders equity		
Common stock	1,588	1,588
Other paid-in capital	5,304	5,190
Retained earnings	806	750
Total shareholders equity	7,698	7,528
Total liabilities and shareholders equity	$ 24,544	$ 24,118

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders Equity
Balance, December 31, 2013	$ 1,588	$ 5,190	$ (1,639)	$ 2,389	$ 7,528
Net income			209		209
Appropriation of retained earnings for future dividends			(209)	209	
Common stock dividends				(153)	(153)
Contribution from parent		112			112
Parent tax matter indemnification		2			2
Balance, June 30, 2014	$ 1,588	$ 5,304	$ (1,639)	$ 2,445	$ 7,698

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	**2014**	**2013**	**2014**	**2013**
Operating revenues				
Operating revenues	$ 656	$ 672	$ 1,648	$ 1,567
Operating revenues from affiliates			1	
Total operating revenues	656	672	1,649	1,567
Operating expenses				
Purchased power and fuel	193	161	570	426
Purchased power from affiliate	48	97	135	238
Operating and maintenance	160	155	416	319
Operating and maintenance from affiliates	24	26	48	50
Depreciation and amortization	59	56	117	113
Taxes other than income	38	39	80	80
Total operating expenses	522	534	1,366	1,226
Operating income	134	138	283	341
Other income and (deductions)				
Interest expense	(25)	(25)	(50)	(51)
Interest expense to affiliates, net	(3)	(3)	(6)	(6)
Other, net	1		3	3
Total other income and (deductions)	(27)	(28)	(53)	(54)
Income before income taxes	107	110	230	287
Income taxes	23	32	57	87
Net income	84	78	173	200
Preferred security dividends and redemption		6		7
Net income attributable to common shareholder	84	72	173	193
Comprehensive income	$ 84	$ 78	$ 173	$ 200

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Six Months Ended June 30, 2014	2013
Cash flows from operating activities		
Net income	$ 173	$ 200
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	117	113
Deferred income taxes and amortization of investment tax credits	6	25
Other non-cash operating activities	50	50
Changes in assets and liabilities:		
Accounts receivable	34	55
Receivables from and payables to affiliates, net	(21)	(18)
Inventories	22	27
Accounts payable, accrued expenses and other current liabilities	30	35
Income taxes	54	39
Pension and non-pension postretirement benefit contributions	(11)	(10)
Other assets and liabilities	(114)	(49)
Net cash flows provided by operating activities	340	467
Cash flows from investing activities		
Capital expenditures	(308)	(254)
Changes in intercompany money pool		(263)
Change in restricted cash		(1)
Other investing activities	6	4
Net cash flows used in investing activities	(302)	(514)
Cash flows from financing activities		
Dividends paid on common stock	(160)	(166)
Dividends paid on preferred securities		(1)
Redemption of preferred securities		(93)
Other financing activities	(2)	1
Net cash flows used in financing activities	(162)	(259)
Decrease in cash and cash equivalents	(124)	(306)
Cash and cash equivalents at beginning of period	217	362
Cash and cash equivalents at end of period	$ 93	$ 56

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 93	$ 217
Restricted cash and cash equivalents	2	2
Accounts receivable, net		
Customer	304	360
Other	107	107
Inventories, net		
Fossil fuel	34	60
Materials and supplies	25	21
Deferred income taxes	80	83
Prepaid utility taxes	78	3
Regulatory assets	29	17
Other	51	36
Total current assets	803	906
Property, plant and equipment, net	6,545	6,384
Deferred debits and other assets		
Regulatory assets	1,495	1,448
Investments	23	23
Investments in affiliates	8	8
Receivable from affiliates	490	447
Prepaid pension asset	359	363
Other	38	38
Total deferred debits and other assets	2,413	2,327
Total assets	$ 9,761	$ 9,617

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Long-term debt due within one year	$ 250	$ 250
Accounts payable	298	285
Accrued expenses	167	106
Payables to affiliates	37	58
Customer deposits	50	49
Regulatory liabilities	88	106
Other	32	37
Total current liabilities	922	891
Long-term debt	1,947	1,947
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,545	2,487
Asset retirement obligations	30	29
Non-pension postretirement benefits obligations	292	286
Regulatory liabilities	671	629
Other	92	99
Total deferred credits and other liabilities	3,630	3,530
Total liabilities	6,683	6,552
Commitments and contingencies		
Shareholder s equity		
Common stock	2,415	2,415
Retained earnings	662	649
Accumulated other comprehensive income, net	1	1
Total shareholder s equity	3,078	3,065
Total liabilities and shareholders equity	$ 9,761	$ 9,617

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDER S EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	Total Shareholder s Equity
Balance, December 31, 2013	$ 2,415	$ 649	$ 1	$ 3,065
Net income		173		173
Common stock dividends		(160)		(160)
Balance, June 30, 2014	$ 2,415	$ 662	$ 1	$ 3,078

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	**2014**	**2013**	**2014**	**2013**
Operating revenues				
Operating revenues	$ 651	$ 649	$ 1,689	$ 1,525
Operating revenues from affiliates	2	4	18	8
Total operating revenues	653	653	1,707	1,533
Operating expenses				
Purchased power and fuel	183	189	592	501
Purchased power from affiliate	85	99	205	212
Operating and maintenance	163	139	326	266
Operating and maintenance from affiliates	25	21	50	37
Depreciation and amortization	89	82	197	175
Taxes other than income	53	54	113	109
Total operating expenses	598	584	1,483	1,300
Operating income	55	69	224	233
Other income and (deductions)				
Interest expense	(23)	(28)	(47)	(58)
Interest expense to affiliates, net	(4)	(4)	(8)	(8)
Other, net	5	4	9	9
Total other income and (deductions)	(22)	(28)	(46)	(57)
Income before income taxes	33	41	178	176
Income taxes	14	16	72	70
Net income	19	25	106	106
Preference stock dividends	3	3	6	6
Net income attributable to common shareholder	16	22	100	100
Comprehensive income	$ 19	$ 25	$ 106	$ 106

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Six Months Ended June 30, 2014	2013
Cash flows from operating activities		
Net income	$ 106	$ 106
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	197	175
Deferred income taxes and amortization of investment tax credits	47	98
Other non-cash operating activities	89	61
Changes in assets and liabilities:		
Accounts receivable	44	(58)
Receivables from and payables to affiliates, net	(12)	(11)
Inventories		4
Accounts payable, accrued expenses and other current liabilities	(74)	(28)
Counterparty collateral received, net	27	
Income taxes	(14)	(33)
Pension and non-pension postretirement benefit contributions	(8)	(11)
Other assets and liabilities	8	63
Net cash flows provided by operating activities	410	366
Cash flows from investing activities		
Capital expenditures	(313)	(264)
Change in restricted cash	(30)	3
Other investing activities	11	4
Net cash flows used in investing activities	(332)	(257)
Cash flows from financing activities		
Changes in short-term borrowings	(65)	
Issuance of long-term debt		300
Retirement of long-term debt	(35)	(33)
Dividends paid on preference stock	(6)	(6)
Other financing activities	12	(2)
Net cash flows (used in) provided by financing activities	(94)	259
Increase (decrease) in cash and cash equivalents	(16)	368
Cash and cash equivalents at beginning of period	31	89
Cash and cash equivalents at end of period	$ 15	$ 457

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 15	$ 31
Restricted cash and cash equivalents	58	28
Accounts receivable, net		
Customer	419	480
Other	102	114
Income taxes receivable	44	30
Inventories, net		
Gas held in storage	48	53
Materials and supplies	33	28
Deferred income taxes	11	2
Prepaid utility taxes		57
Regulatory assets	178	181
Other	8	7
Total current assets	916	1,011
Property, plant and equipment, net	6,030	5,864
Deferred debits and other assets		
Regulatory assets	499	524
Investments	4	5
Investments in affiliates	8	8
Prepaid pension asset	396	423
Other	24	26
Total deferred debits and other assets	931	986
Total assets[(a)]	$ 7,877	$ 7,861

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 70	$ 135
Long-term debt due within one year	72	70
Accounts payable	205	270
Accrued expenses	95	111
Deferred income taxes	39	27
Payables to affiliates	55	55
Customer deposits	87	76
Regulatory liabilities	63	48
Other	61	35
Total current liabilities	747	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	1,814	1,773
Asset retirement obligations	17	19
Non-pension postretirement benefits obligations	215	217
Regulatory liabilities	202	204
Other	65	67
Total deferred credits and other liabilities	2,313	2,280
Total liabilities[(a)]	5,222	5,306
Commitments and contingencies		
Shareholders equity		
Common stock	1,360	1,360
Retained earnings	1,105	1,005
Total shareholder s equity	2,465	2,365
Preference stock not subject to mandatory redemption	190	190
Total equity	2,655	2,555
Total liabilities and shareholders equity	$ 7,877	$ 7,861

(a) BGE s consolidated assets include $31 million and $31 million at June 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 $234 million and $269 million at June 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.

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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		106	106		106
Preference stock dividends		(6)	(6)		(6)
Balance, June 30, 2014	$ 1,360	$ 1,105	$ 2,465	$ 190	$ 2,655

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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 CENG 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 the Exelon, Generation and BGE Consolidated Statement of Operations have been reclassified between line items for comparative purposes and correction of prior period classification errors identified in 2013. The reclassifications did not affect any of the Registrants net income or cash flows from operating activities. Exelon corrected the presentation of Purchased power and fuel from affiliates of $287 million and $605 million on its Statements of Operations and Comprehensive Income for the three and six months ended June 30, 2013, respectively. Generation corrected the presentation of Purchased power and fuel from affiliates of $290 million and $611 million on its Statements of Operations and Comprehensive Income for the three and six months ended June 30, 2013, respectively. Generation also corrected the presentation of Interest expense to affiliates, net of $16 million and $34 million on its Statement of Operations and Comprehensive Income for the three and six months ended June 30, 2013, respectively. BGE corrected its presentation of Interest expense to affiliates, net of $4 million and $8 million on the Statement of Operations and Comprehensive Income for the three and six months ended June 30, 2013, respectively.

The accompanying consolidated financial statements as of June 30, 2014 and 2013 and for the six months then ended are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2013 Consolidated Balance Sheets were obtained from audited financial statements. Financial results for interim

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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 June 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 detail by Registrant below).* As of June 30, 2014 and December 31, 2013, the Registrants had significant interests in nine and eight other VIEs, respectively, 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 EDFI 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; 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 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 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 conveyed through the NOSA. Further, since Generation is conducting the operational activities of CENG, 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 non-controlling 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 three and six months ended June 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 did 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,

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Constellation Energy Nuclear Group, Inc. (CENG).

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

As of June 30, 2014 and December 31, 2013, Exelon, Generation, and BGE provided the following support to the 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 six months ended June 30, 2014, BGE remitted $21 million and $42 million, respectively, to BondCo. During the three and six months ended June 30, 2013, BGE remitted $17 million and $39 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 Nuclear Operating Services Agreement (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 of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF Inc. (EDFI) (a subsidiary of EDF),

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

under power purchase agreements with CENG, Generation will purchase 85% of the available output generated by CENG nuclear plants for the remainder of 2014 and 50.01% from 2015 through the end of the life of each respective plant under power purchase agreements with CENG,

Generation provided a $400 million loan to CENG,

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 18 Commitments and Contingencies for more details), in connection with CENG s severance obligations, Generation has agreed to reimburse CENG for a total of approximately $6 million of the severance benefits paid or to be paid in 2013 through 2016. As of June 30, 2014, the remaining obligation is approximately $4 million (See Integration-Related Severance under Note 14 Severance for additional details),

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),

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Generation provides a $7 million guarantee 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, 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 June 30, 2014 and December 31, 2013 are as follows:

	June 30, 2014			December 31, 2013		
	Exelon[(a)(b)]	Generation[(b)]	BGE	Exelon[(a)]	Generation	BGE
Current assets	$ 991	$ 956	$ 28	$ 484	$ 446	$ 28
Noncurrent assets	7,426	7,407	3	1,905	1,884	3
Total assets	$ 8,417	$ 8,363	$ 31	$ 2,389	$ 2,330	$ 31
Current liabilities	$ 815	$ 732	$ 76	$ 566	$ 481	$ 74

Noncurrent liabilities	2,911	2,738	158	774	562	195
Total liabilities	$ 3,726	$ 3,470	$ 234	$ 1,340	$ 1,043	$ 269

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

(b) Includes total assets of $5.8 billion and total liabilities of $2.4 billion due to the consolidation of CENG begining April 1, 2014. See Note 6 Investment in CENG for additional information.

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

	June 30, 2014			December 31, 2013		
	Exelon	Generation	BGE	Exelon	Generation	BGE
Cash and cash equivalents	$ 126	$ 126	$	$ 62	$ 62	$
Restricted cash	75	47	28	80	52	28
Accounts receivable, net						
Customer	296	296		260	260	
Other	133	133				
Inventory						
Fossil fuel	103	103		2	2	
Materials and supplies	165	165				
Other current assets	61	54		53	42	
Total current assets	959	924	28	457	418	28
Property, plant and equipment, net	4,603	4,603		1,171	1,171	
Nuclear decommissioning trust funds	2,030	2,030				
Goodwill	48	48				
Other noncurrent assets	125	106	3	127	106	3
Total noncurrent assets	6,806	6,787	3	1,298	1,277	3
Total assets	$ 7,765	$ 7,711	$ 31	$ 1,755	$ 1,695	$ 31
Short-term borrowings	$ 40	$ 40	$	$	$	$
Long-term debt due within one year	84	5	72	85	5	70
Accounts payable	243	243		170	170	
Accrued expenses	89	86	4	26	22	4
Mark-to-market derivative liabilities	24	24		29	29	
Unamortized energy contracts	12	12		5	5	
Other current liabilities	165	165		5	5	
Total current liabilities	657	575	76	320	236	74
Long-term debt	258	84	158	298	86	195
Asset retirement obligations	1,731	1,731				
Pension obligation[(a)]	133	133				
Non-pension postretirement benefit	136	136				
Unamortized energy contracts	18	18		12	12	
Other noncurrent liabilities	178	178		28	28	
Noncurrent liabilities	2,454	2,280	158	338	126	195
Total liabilities	$ 3,111	$ 2,855	$ 234	$ 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,

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

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 June 30, 2014 and December 31, 2013, Exelon and Generation had significant unconsolidated variable interests in nine and eight VIEs, respectively, for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity method investments and certain commercial agreements. The increase in the number of unconsolidated VIEs is due to an investment in another unconsolidated VIE and the execution of an energy purchase and sale agreement with an unconsolidated VIE, offset by the sale of Generation s ownership interest in one unconsolidated VIE. The following tables present summary information about Exelon and Generation s significant unconsolidated VIE entities:

June 30, 2014	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 119	$ 325	$ 444
Total liabilities[(a)]	2	120	122
Exelon s ownership interest in VIE[(a)]		63	63
Other ownership interests in VIE[(a)]	117	142	259
Registrants maximum exposure to loss:			
Carrying amount of equity method investments		73	73
Contract intangible asset	9		9
Debt and payment guarantees		3	3
Net assets pledged for Zion Station decommissioning[(b)]	45		45

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.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(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 $402 million and $458 million as of June 30, 2014 and December 31, 2013, respectively; offset by payables to ZionSolutions LLC of $357 million and $414 million as of June 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 $90 million of PHI preferred securities are included in Other non-current assets on Exelon s Consolidated Balance Sheet as of June 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.

The transaction must be approved by the shareholders of PHI. Completion of the transaction is also conditioned upon approval by the FERC, the District of Columbia Public Service Commission and several state commissions including Delaware Public Service Commission, MDPSC, the New Jersey Board of Public Utilities and the Virginia Department of Public Utilities. In addition, 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 Federal Trade Commission (FTC) and/or the Antitrust Division of the United States Department of Justice (DOJ) and until specified waiting period requirements have expired.

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. 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 June 30, 2014, Exelon has incurred approximately $25 million of expense associated with the transaction, primarily related to fees incurred as part of the acquisition. As part of the applications for approval of the merger, Exelon and PHI have proposed a package of benefits to PHI utilities customers which results 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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. The companies anticipate closing the transaction in the second or third quarter of 2015, subject to receipt of required regulatory approvals.

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 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 $4.2 billion as a result of the equity issuances. See Note 10 Debt and Credit Agreements and Note 16 Common Stock for more information.

Safe Harbor Water Power Corporation (Exelon and Generation)

On May 15, 2014, Generation entered into a Purchase and Sale Agreement with Brookfield Renewable Energy Partners L.P. to sell Generation s 67% economic equity interest in the 417 MW Safe Harbor Water Power Corporation hydroelectric facility on the Susquehanna River in Pennsylvania (Safe Harbor). The total purchase price for the transaction is approximately $613 million. The transaction, which is subject to customary closing conditions and regulatory approvals, is expected to be completed in the third quarter of 2014, at which time Generation anticipates recording a pre-tax gain of approximately $332 million. The after-tax net cash proceeds of $375 million are expected to be used to finance a portion of the acquisition of PHI and for general corporate purposes.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

expected to be approved by the ICC for that year s reconciliation. As of June 30, 2014, and December 31, 2013, ComEd had recorded a net regulatory asset associated with the distribution formula rate of $439 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.

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 350,000 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. On December 20, 2012, the ICC issued its final order, which increased the revenue requirement by $73 million, in conformity with the formula rate structure provided in the ICC s May 2012 and Rehearing Orders. 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 in the Appeal of the 2012 Formula Rate Tariff. Two of the three issues appealed (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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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, the ICC filed its Answer to the Petition, arguing that Supreme Court review is not necessary or appropriate. Under the rules, ComEd is not allowed to reply to the ICC filing. There is no set time by which the Court must decide rule on the Petition. ComEd cannot predict whether the Court will grant the appeal, or if it does, the ultimate outcome.

Advanced Metering Program Proceeding (Exelon and ComEd). As part of ComEd s 2007 electric distribution rate case, the ICC approved recovery of costs associated with ComEd s System Modernization Program (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 June 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 proposed agreement to jointly resolve the disputed refund claim. Any joint agreement must ultimately be approved by the ICC through its investigation. At June 30, 2014, ComEd recorded a regulatory liability of approximately $9 million based on its assessment of the likely outcome of the matter. ComEd cannot predict the ultimate outcome of the ICC s investigation and therefore, actual refunds, if any, may differ from the estimated liability recorded at June 30, 2014.

Grand Prairie Gateway Transmission Line (ComEd). On December 2, 2013, ComEd filed a request to obtain the ICC s approval to construct a 57-mile, overhead 345kV transmission line that traverses Ogle, DeKalb, Kane and DuPage Counties in Northern Illinois. Numerous stakeholders are participating in the proceeding and ComEd expects the ICC to rule on its request by October 27, 2014. 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

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 June 30, 2014, ComEd has completed the first ICC-approved procurement process for 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.

During 2013, the ICC approved, and directed ComEd and Ameren (the Utilities) to enter into 20-year sourcing agreements with FutureGen Industrial Alliance, Inc (FutureGen), under which FutureGen will retrofit and repower an existing plant in Morgan County, Illinois to a 166 MW near zero emissions coal-fueled generation plant, with an assumed commercial operation date in 2017. The sourcing agreement provides that the Utilities 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 the Utilities to recover (or pass along) these costs from the Utilities distribution system customers, regardless of whether they purchase electricity from the utility 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 contract with FutureGen and allowing ComEd to recover the associated costs from retail customers purchasing electricity from both ComEd and competitive electric generation suppliers. ComEd is assessing the Court s order and is in process of determining the appropriate course of action.

On August 22, 2013, the Utilities executed the sourcing agreement with FutureGen in accordance with the ICC order. However, in the event the order is reversed as a result of the appeal, ComEd s obligations under the sourcing agreement would be suspended. In June 2014, ComEd filed a petition with the ICC seeking approval of a tariff allowing ComEd to recover its costs associated with the FutureGen contract from all of its delivery service customers. An order approving that tariff is expected before the end of 2014. Depending on the ultimate outcome of the outstanding appeals, and petitions, the 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.

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

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 and 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 and 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 and small, medium, and large commercial classes that began in June 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 late 2014.

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. A PAPUC ruling is expected in late 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 June 30, 2014, PECO has spent $480 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 June 30, 2014, PECO has received $198 million, including $4 million for sub-recipients, of the $200 million in reimbursements. PECO s outstanding receivable from the DOE for reimbursable costs was $2 million as of June 30, 2014, which has been recorded in Other accounts receivable, net on Exelon s and PECO s Consolidated Balance Sheets.

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 continue to be allowable costs and that any settlement with the vendor will 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 June 30, 2014, with no gain or loss impacts on future results of operations.

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.

The peak demand period ended on September 30, 2012 and 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.

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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.

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. The new electric and gas distribution base rates are expected to take effect in late January 2015. BGE cannot predict the outcome of this proceeding or how much of the requested increases the MDPSC will approve.

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

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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 nature of the appeal will not be known until further pleadings are filed by the residential consumer advocate. 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 June 30, 2014 and December 31, 2013, BGE recorded a regulatory asset of $94 million and $66 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program. Additionally, the MDPSC has determined that the cost recovery for the non-AMI meters that BGE retires will be considered in a future depreciation proceeding.

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, 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. 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 promptly recover 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 Exelon and BGE as of June 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 has until August 7, 2014 to submit a response, and a hearing has been scheduled for September 5, 2014. BGE cannot predict the outcome of this appeal.

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 June 30, 2014, and December 31, 2013, ComEd had recorded a net regulatory asset associated with the transmission formula rate of $10 million and $17 million, respectively, and BGE had recorded a net regulatory asset associated with the transmission formula rate of $4 million and a net regulatory liability of $0 million, respectively. 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 will take 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%, 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 filings 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 net revenue requirement of $171 million. This compares to the 2013 revenue requirement of $158 million offset by a $1 million reduction related

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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%, 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. As of June 30, 2014, BGE believes it is probable that BGE s base ROE rate will be subject to the revised methodology and may result in a potential refund to customers of transmission revenue for a maximum fifteen month period. In evaluating FERC s revised methodology, management believes it is reasonably possible no refunds will be required for BGE, and as such, no refund liability has been recorded as of June 30, 2014. If FERC were to order a reduction of BGE s base return on equity to 8.7% as sought in the 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

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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. In addition, on July 7, 2014, FERC and several other parties sought rehearing of the D.C. Circuit Decision. Therefore, FERC will not be required to implement the D.C. Circuit Decision until at the earliest a determination is made on the rehearing request. If rehearing is denied, FERC or other parties will have an opportunity to appeal the decision to the United States Supreme Court. The final outcome of this litigation is therefore 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.

FERC Deficiency Letter Related to 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 is deficient and that ISO-NE must file additional information before the FERC can process the filing. ISO-NE has 30 days to file the information and then FERC will determine how to proceed. Exelon cannot predict when the FERC will accept the capacity auction results for filing or what further action FERC may take concerning the results of that auction, but any FERC action could be material to Exelon s expected revenues from the capacity auction.

License Renewals (Exelon and Generation). On June 22, 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years. The current operating licenses for Limerick Units 1 and 2 expire in 2024 and 2029, respectively. 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. In September 2012, the NRC directed NRC Staff to revise the temporary storage rule which is now not expected until October 3, 2014. Generation does not expect the NRC to issue license renewals until the end of 2014, at the earliest.

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. 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. 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.

Based on the latest FERC procedural schedule, the FERC licensing process is not expected to be completed prior to the expiration of Muddy Run s current license on August 31, 2014, and the expiration of Conowingo s

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

license on September 1, 2014. However, the stations would continue to operate under annual licenses until FERC takes action on the 46-year license applications. The stations are currently being depreciated over their estimated useful lives, which includes the license renewal period. As of June 30, 2014, $36 million of direct costs associated with licensing efforts have been capitalized.

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 June 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.

June 30, 2014	**Exelon**		**ComEd**		**PECO**		**BGE**	
	Current	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**
Regulatory assets								
Pension and other postretirement benefits	$ 208	$ 2,510	$	$	$	$	$	$
Deferred income taxes	13	1,495	1	68		1,358	12	69
AMI programs	7	222	7	56		72		94
Under-recovered distribution service costs	219	220	219	220				
Debt costs	10	51	8	49	2	2	1	8
Fair value of BGE long-term debt[(a)]	7	198						
Fair value of BGE supply contract[(b)]	6							
Severance	4	11					4	11
Asset retirement obligations	1	110	1	73		26		11
MGP remediation costs	40	196	33	165	6	30	1	1
RTO start-up costs	1		1					
Under-recovered uncollectible accounts		70		70				
Renewable energy	13	121	13	121				
Energy and transmission programs	17	4	12				5[(f)]	4
Deferred storm costs	3	1					3	1
Electric generation-related regulatory asset	13	24					13	24
Rate stabilization deferral	73	119					73	119
Energy efficiency and demand response programs	63	148					63	148
Merger integration costs	2	7					2	7
Conservation voltage reduction		1						1
Other	32	37	9	28	21	7	1	1
Total regulatory assets	$ 732	$ 5,545	$ 304	$ 850	$ 29	$ 1,495	$ 178	$ 499

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

June 30, 2014	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Other postretirement benefits	$ 53	$ 111	$	$	$	$	$	$
Nuclear decommissioning		2,917		2,427		490		
Removal costs	107	1,449	83	1,248			24	201
Energy efficiency and demand response programs	14	2	14			2		
DLC Program Costs	1	9			1	9		
Energy efficiency Phase 2		32				32		
Electric distribution tax repairs	20	104			20	104		
Gas distribution tax repairs	8	34			8	34		
Energy and transmission programs	89	11	19	11	52[c]		18[f]	
Over-recovered gas and electric universal service fund costs	5				5			
Revenue subject to refund[d]	47		47					
Over-recovered gas and electric revenue decoupling[e]	21						21	
Other	3	1	1		2			1
Total regulatory liabilities	$ 368	$ 4,670	$ 164	$ 3,686	$ 88	$ 671	$ 63	$ 202

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

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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 electric and gas 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. See Note 10 Debt and Credit Agreements for additional information.

(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 $26 million related to the DSP program, $19 million related to the over-recovered natural gas costs under the PGC and $7 million related to over-recovered electric transmission costs as of June 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 June 30, 2014, BGE had a regulatory liability of $3 million related to over-recovered electric revenue decoupling and $18 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 $1 million of under-recovered electric supply costs, $4 million associated with the transmission formula rate and $18 million of over-recovered natural gas supply costs as of June 30, 2014. As of December 31, 2013, includes $1 million of under-recovered electric supply costs, $0 million associated with the transmission formula rate 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 June 30, 2014 and December 31, 2013.

As of June 30, 2014	Exelon	ComEd	PECO	BGE
Purchased receivables[(a)]	$ 270	$ 116	$ 75	$ 79
Allowance for uncollectible accounts[(b)]	(32)	(17)	(8)	(7)
Purchased receivables, net	$ 238	$ 99	$ 67	$ 72

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 and subsidiaries of Generation, EDF, EDF, Inc. (EDFI) (a subsidiary of EDF) and 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 of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to EDFI s 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

The parties also executed a Fourth Amended and Restated Operating Agreement for CENG 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 the assumption of the employee benefit plans and their related trusts by Exelon as the plan sponsor as of July 14, 2014. The EMA also generally requires CENG to fund 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 CENG (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 on April 1, 2014 when the NRC licenses were transferred to Generation. No liability has been recognized by Exelon for the guarantees.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

revenues from CENG. For the three and six months ended June 30, 2013, Generation recorded $19 million and $31 million, respectively, of equity in losses of unconsolidated affiliates related to its investment in CENG and $23 million and $34 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. Sales to EDF of $38 million are included within Exelon s and Generation s Consolidated Statements of Operations for the three and six months ended June 30, 2014. 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 non-controlling 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 our 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. 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.

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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	2,958
Nuclear fuel	482
Other assets	10
Total assets	5,904
Current liabilities	237
Asset retirement obligation	1,701
Pension and other employee benefit obligations	281
Unamortized energy contract liabilities	171
Other liabilities	114
Total liabilities	2,504
Total net assets	$ 3,400

Generation also recorded the fair value of the non-controlling 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 non-controlling 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 non-controlling 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 months ended June 30, 2014, Generation reduced by $4 million the amount of Net income attributable to non-controlling 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 $98 million and CENG s net income, prior to any intercompany eliminations and any adjustments for non-controlling interest, of $76 million during the three and six months ended June 30, 2014.

During the three and six months ended June 30, 2014, Exelon and Generation incurred integration-related costs of $11 million and $18 million, respectively. 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 six months ended June 30, 2014.

See Note 14 Severance for integration-related severance costs incurred by Exelon and Generation during the three and six months ended June 30, 2014.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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. The fair value analysis 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. 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 in Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. Changes in the assumptions described above could potentially result in future impairments of Exelon s long-lived assets, which could be material.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 leases on the generating station located in Texas, as described above, prior to its expiration dates. 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 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.

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

	June 30, 2014	December 31, 2013
Estimated residual value of leased assets	$ 685	$ 1,465
Less: unearned income	332	767
Net investment in long-term leases	$ 353	$ 698

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

8. Fair Value of Financial Assets and Liabilities (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 June 30, 2014 and December 31, 2013:

Exelon

	June 30, 2014				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 624	$ 3	$ 621	$	$ 624
Long-term debt (including amounts due within one year)	20,180	1,150	19,373	1,135	21,658
Long-term debt to financing trusts	648			668	668
SNF obligation	1,021		814		814

	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

	June 30, 2014				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 53	$	$ 53	$	$ 53
Long-term debt (including amounts due within one year)	7,507		6,881	1,135	8,016
SNF obligation	1,021		814		814

	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

	June 30, 2014				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 498	$	$ 498	$	$ 498
Long-term debt (including amounts due within one year)	5,708		6,452		6,452
Long-term debt to financing trust	206			211	211

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

		December 31, 2013			
		Fair Value			
	Carrying Amount	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

		June 30, 2014			
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 2,197	$	$ 2,436	$	$ 2,436
Long-term debt to financing trusts	184			198	198

		December 31, 2013			
		Fair Value			
	Carrying Amount	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

		June 30, 2014			
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 73	$ 3	$ 70	$	$ 73
Long-term debt (including amounts due within one year)	1,976		2,206		2,206
Long-term debt to financing trusts	258			259	259

		December 31, 2013			
		Fair Value			
	Carrying Amount	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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 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.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 six months ended June 30, 2014 for cash equivalents, nuclear decommissioning trust fund investments, pledged assets for Zion Station decommissioning, Rabbi trust investments, and deferred compensation obligations.

Exelon

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

As of June 30, 2014	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents[(a)]	$ 1,034	$	$	$ 1,034
Nuclear decommissioning trust fund investments				
Cash equivalents	151	66		217
Equity				
Individually held	2,572			2,572
Exchange traded funds	164			164
Commingled funds		2,529		2,529
Equity funds subtotal	2,736	2,529		5,265
Balanced funds commingled funds		273		273
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	990			990
Debt securities issued by states of the United States and political subdivisions of the states		416		416
Debt securities issued by foreign governments		114		114
Corporate debt securities		2,059	181	2,240
Federal agency mortgage-backed securities		84		84
Commercial mortgage-backed securities (non-agency)		43		43
Residential mortgage-backed securities (non-agency)		3		3
Mutual funds		18		18
Commingled funds		325		325
Fixed income subtotal	990	3,062	181	4,233
Middle market lending			376	376
Private Equity			35	35
Other debt obligations		24		24
Nuclear decommissioning trust fund investments subtotal[(b)]	3,877	5,954	592	10,423
Pledged assets for Zion Station decommissioning				
Cash equivalents		45		45
Equity				
Individually held	4	2		6

Equity funds subtotal	4	2		6
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	12	3		15
Debt securities issued by states of the United States and political subdivisions of the states		19		19
Corporate debt securities		172		172
Commingled funds		5		5
Fixed income subtotal	12	199		211
Middle market lending			133	133
Pledged assets for Zion Station decommissioning subtotal(c)	16	246	133	395

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of June 30, 2014	**Level 1**	**Level 2**	**Level 3**	**Total**
Rabbi trust investments[e]				
Cash equivalents	2			2
Mutual funds[d]	43			43
Rabbi trust investments subtotal	45			45
Commodity derivative assets				
Economic hedges	434	2,969	1,413	4,816
Proprietary trading	178	712	184	1,074
Effect of netting and allocation of collateral[f]	(569)	(3,119)	(1,127)	(4,815)
Commodity derivative assets subtotal	43	562	470	1,075
Interest rate and foreign currency derivative assets	24	40		64
Effect of netting and allocation of collateral	(21)	(7)		(28)
Interest rate and foreign currency derivative assets subtotal	3	33		36
Other investments	13		10	23
Total assets	5,031	6,795	1,205	13,031
Liabilities				
Commodity derivative liabilities				
Economic hedges	(434)	(2,803)	(1,465)	(4,702)
Proprietary trading	(182)	(707)	(176)	(1,065)
Effect of netting and allocation of collateral[f]	618	3,408	1,279	5,305
Commodity derivative liabilities subtotal	2	(102)	(362)	(462)
Interest rate and foreign currency derivative liabilities	(24)	(34)		(58)
Effect of netting and allocation of collateral	24	6		30
Interest rate and foreign currency derivative liabilities subtotal		(28)		(28)
Deferred compensation obligation		(104)		(104)
Total liabilities	2	(234)	(362)	(594)
Total net assets	$ 5,033	$ 6,561	$ 843	$ 12,437

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of December 31, 2013	**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
Debt securities issued by states of the United States and political subdivisions of the states		20		20
Corporate debt securities		227		227
Fixed income subtotal	45	251		296
Middle market lending			112	112
Other debt obligations		1		1
Pledged assets for Zion Station decommissioning subtotal[c]	61	278	112	451
Rabbi trust investments[e]				
Cash equivalents	2			2
Mutual funds[d]	54			54
Rabbi trust investments subtotal	56			56
Commodity derivative assets				
Economic hedges	493	2,582	885	3,960
Proprietary trading	324	1,315	122	1,761
Effect of netting and allocation of collateral[f]	(863)	(3,131)	(430)	(4,424)
Commodity derivative assets subtotal	(46)	766	577	1,297
Interest rate and foreign currency derivative assets	30	39		69
Effect of netting and allocation of collateral	(30)	(2)		(32)
Interest rate and foreign currency derivative assets subtotal		37		37
Other Investments			15	15
Total assets	4,533	5,575	1,054	11,162
Liabilities				
Commodity derivative liabilities				
Economic hedges	(540)	(1,890)	(590)	(3,020)
Proprietary trading	(328)	(1,256)	(119)	(1,703)
Effect of netting and allocation of collateral[f]	869	3,007	404	4,280
Commodity derivative liabilities subtotal	1	(139)	(305)	(443)
Interest rate and foreign currency derivative liabilities	(31)	(17)		(48)
Effect of netting and allocation of collateral	31	1		32
Interest rate and foreign currency derivative liabilities subtotal		(16)		(16)
Deferred compensation obligation		(114)		(114)
Total liabilities	1	(269)	(305)	(573)
Total net assets	$ 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 June 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 $7 million at both June 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 include $42 million related to deferred compensation and $1 million related to Supplemental Executive Retirement Plan at June 30, 2014, and $53 million related to deferred compensation and $1 million related to Supplemental Executive Retirement Plan at December 31, 2013.
(e) Excludes $34 million and $32 million of the cash surrender value of life insurance investments at June 30, 2014 and December 31, 2013, respectively.
(f) Includes collateral postings to counterparties. Collateral posted to counterparties, net of collateral paid to counterparties, totaled $49 million, $289 million and $152 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of June 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.

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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 six months ended June 30, 2014 and 2013:

Three Months Ended June 30, 2014	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of March 31, 2014	$ 486	$ 137	$ 119	$ 10	$ 752
Total realized / unrealized gains (losses)					
Included in net income	2		(48)[(a)]		(46)
Included in other comprehensive income					
Included in regulatory assets	8		34		42
Included in payable for Zion Station decommissioning		4			4
Change in collateral			34		34
Purchases, sales, issuances and settlements					
Purchases	109	13	5		127
Sales	(1)	(21)	(4)		(26)
Settlements	(12)				(12)
Transfers into Level 3			(4)		(4)
Transfers out of Level 3			(28)		(28)
Balance as of June 30, 2014	$ 592	$ 133	$ 108	$ 10	$ 843
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 June 30, 2014	$ 2	$	$ 19	$	$ 21

Six Months Ended June 30, 2014	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2013	$ 350	$ 112	$ 272	$ 15	$ 749
Total realized / unrealized gains (losses)					
Included in net income	3		(360)[(a)]		(357)
Included in other comprehensive income					
Included in regulatory assets	11		59		70
Included in payable for Zion Station decommissioning		4			4
Change in collateral			178		178
Purchases, sales, issuances and settlements					
Purchases	249	42	15	2	308
Sales	(2)	(25)	(6)		(33)
Settlements	(19)				(19)
Transfers into Level 3			(30)		(30)
Transfers out of Level 3			(20)	(7)	(27)

Balance as of June 30, 2014	$ 592	$ 133	$ 108	$ 10	$ 843
The amount of total losses included in income attributed to the change in unrealized gains related to assets and liabilities held for the nine months ended June 30, 2014	$ 2	$	$ (427)	$	$ (425)

(a) Includes the increase for the reclassification of $67 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three months ended June 30, 2014.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Three Months Ended June 30, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of March 31, 2013	$ 210	$ 104	$ 260	$ 9	$ 583
Total realized / unrealized gains (losses)					
Included in net income	1		158[(a)]		159
Included in other comprehensive income					
Included in regulatory assets	8		(10)[(b)]		(2)
Included in payable for Zion Station decommissioning		1			1
Change in collateral			10		10
Purchases, sales, issuances and settlements					
Purchases	35	11	13	2	61
Sales	(11)	(5)	(4)		(20)
Settlements	(3)				(3)
Transfers into Level 3			3		3
Transfers out of Level 3			1		1
Balance as of June 30, 2013	$ 240	$ 111	$ 431	$ 11	$ 793
The amount of total losses included in income attributed to the change in unrealized losses related to assets and liabilities held for the three months ended June 30, 2013	$ 1	$	$ 187	$	$ 188

Six Months Ended June 30, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2012	$ 183	$ 89	$ 367	$ 17	$ 656
Total realized / unrealized gains (losses)					
Included in net income	2		31[(a)]		33
Included in other comprehensive income					
Included in regulatory assets	9		(18)[(b)]		(9)
Included in payable for Zion Station decommissioning		1			1
Change in collateral			43		43
Purchases, sales, issuances and settlements					
Purchases	67	33	8[(c)]	2	110
Sales	(13)	(12)	(8)	(8)	(41)
Settlements	(8)				(8)
Transfers into Level 3			7		7
Transfers out of Level 3			1		1
Balance as of June 30, 2013	$ 240	$ 111	$ 431	$ 11	$ 793
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the six months ended	$ 1	$	$ 108	$	$ 109

June 30, 2013

(a) Includes the reclassification of $29 million and $77 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and six months ended June 30, 2013, respectively.
(b) Excludes decreases in fair value of $3 million and $11 million and realized losses reclassified due to settlements of $82 million and $215 million associated with Generation s financial swap contract with ComEd for the three and six months ended June 30, 2013. All items eliminate upon consolidation in Exelon s Consolidated Financial Statements.
(c) Includes $10 million which Generation was paid to enter into out of the money purchase contracts.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

	Operating Revenue	Purchased Power and Fuel	Other, net[(a)]
Total gains (losses) included in income for the three months ended June 30, 2014	$ (62)	$ 14	$ 2
Total gains (losses) included in income for the six months ended June 30, 2014	$ (330)	$ (30)	$ 3
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2014	$ (10)	$ 29	$ 2
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2014	$ (435)	$ 8	$ 2

	Operating Revenue	Purchased Power and Fuel	Other, net[(a)]
Total gains included in income for the three months ended June 30, 2013	$ 137	$ 21	$ 1
Total gains (losses) included in income for the six months ended June 30, 2013	$ (22)	$ 53	$ 2
Change in the unrealized gains relating to assets and liabilities held for the three months ended June 30, 2013	$ 156	$ 31	$ 1
Change in the unrealized gains relating to assets and liabilities held for the six months ended June 30, 2013	$ 39	$ 69	$ 1

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Generation

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

As of June 30, 2014	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents[(a)]	$ 65	$	$	$ 65
Nuclear decommissioning trust fund investments				
Cash equivalents	151	66		217
Equity				
Individually held	2,572			2,572
Exchange traded funds	164			164
Commingled funds		2,529		2,529
Equity funds subtotal	2,736	2,529		5,265
Balanced funds commingled funds		273		273
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	990			990
Debt securities issued by states of the United States and political subdivisions of the states		416		416
Debt securities issued by foreign governments		114		114
Corporate debt securities		2,059	181	2,240
Federal agency mortgage-backed securities		84		84
Commercial mortgage-backed securities (non-agency)		43		43
Residential mortgage-backed securities (non-agency)		3		3
Mutual funds		18		18
Commingled funds		325		325
Fixed income subtotal	990	3,062	181	4,233
Middle market lending			376	376
Private Equity			35	35
Other debt obligations		24		24
Nuclear decommissioning trust fund investments subtotal[(b)]	3,877	5,954	592	10,423
Pledged assets for Zion Station decommissioning				
Cash equivalents		45		45
Equity				
Individually held	4	2		6
Equity funds subtotal	4	2		6
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	12	3		15
Debt securities issued by states of the United States and political subdivisions of the states		19		19

Corporate debt securities		172		172
Commingled funds		5		5
Fixed income subtotal	12	199		211
Middle market lending			133	133
Pledged assets for Zion Station decommissioning subtotal(c)	16	246	133	395
Rabbi trust investments(d)				
Cash equivalents	1			1
Mutual funds	14			14
Rabbi trust investments subtotal	15			15
Commodity derivative assets				
Economic hedges	434	2,969	1,413	4,816
Proprietary trading	178	712	184	1,074
Effect of netting and allocation of collateral(e)	(569)	(3,119)	(1,127)	(4,815)
Commodity derivative assets subtotal	43	562	470	1,075
Interest rate and foreign currency derivative assets	24	22		46
Effect of netting and allocation of collateral	(21)	(7)		(28)
Interest rate and foreign currency derivative assets subtotal	3	15		18
Other investments	13		10	23
Total assets	4,032	6,777	1,205	12,014

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of June 30, 2014	Level 1	Level 2	Level 3	Total
Liabilities				
Commodity derivative liabilities				
Economic hedges	(434)	(2,803)	(1,331)	(4,568)
Proprietary trading	(182)	(707)	(176)	(1,065)
Effect of netting and allocation of collateral[e]	618	3,408	1,279	5,305
Commodity derivative liabilities subtotal	2	(102)	(228)	(328)
Interest rate and foreign currency derivative liabilities	(24)	(28)		(52)
Effect of netting and allocation of collateral	24	6		30
Interest rate and foreign currency derivative liabilities subtotal		(22)		(22)
Deferred compensation obligation		(29)		(29)
Total liabilities	2	(153)	(228)	(379)
Total net assets	$ 4,034	$ 6,624	$ 977	$ 11,635

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

Equity				
Individually held	16			16
Equity funds subtotal	16			16
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	45	4		49
Debt securities issued by states of the United States and political subdivisions of the states		20		20
Corporate debt securities		227		227
Fixed income subtotal	45	251		296
Middle market lending			112	112
Other debt obligations		1		1
Pledged assets for Zion Station decommissioning subtotal[c]	61	278	112	451
Rabbi trust investments[d]				
Mutual funds	13			13
Rabbi trust investments subtotal	13			13

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Commodity derivative assets				
Economic hedges	493	2,582	885	3,960
Proprietary trading	324	1,315	122	1,761
Effect of netting and allocation of collateral[(e)]	(863)	(3,131)	(430)	(4,424)
Commodity and foreign currency assets subtotal	(46)	766	577	1,297
Interest rate and foreign currency derivative assets	30	32		62
Effect of netting and allocation of collateral	(30)	(2)		(32)
Interest rate and foreign currency derivative assets subtotal		30		30
Other investments			15	15
Total assets	4,266	5,568	1,054	10,888
Liabilities				
Commodity derivative liabilities				
Economic hedges	(540)	(1,890)	(397)	(2,827)
Proprietary trading	(328)	(1,256)	(119)	(1,703)
Effect of netting and allocation of collateral[(e)]	869	3,007	404	4,280
Commodity derivative liabilities subtotal	1	(139)	(112)	(250)
Interest rate derivative liabilities	(31)	(13)		(44)
Effect of netting and allocation of collateral	31	1		32
Interest rate and foreign currency derivative liabilities		(12)		(12)
Deferred compensation obligation		(29)		(29)
Total liabilities	1	(180)	(112)	(291)
Total net assets	$ 4,267	$ 5,388	$ 942	$ 10,597

(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 June 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 $7 million at both June 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) Excludes $10 million of the cash surrender value of life insurance investments at both June 30, 2014 and December 31, 2013.
(e) Includes collateral postings to counterparties. Collateral posted to counterparties, net of collateral paid to counterparties, totaled $49 million, $289 million and $152 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of June 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.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2014 and 2013:

Three Months Ended June 30, 2014	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of March 31, 2014	$ 486	$ 137	$ 287	$ 10	$ 920
Total realized / unrealized gains (losses)					
Included in net income	2		(48)[(a)]		(46)
Included in noncurrent payables to affiliates	8				8
Included in payable for Zion Station decommissioning		4			4
Change in collateral			34		34
Purchases, sales, issuances and settlements					
Purchases	109	13	5		127
Sales	(1)	(21)	(4)		(26)
Settlements	(12)				(12)
Transfers into Level 3			(4)		(4)
Transfers out of Level 3			(28)		(28)
Balance as of June 30, 2014	$ 592	$ 133	$ 242	$ 10	$ 977
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 June 30, 2014	$ 2	$	$ 19	$	$ 21

Six Months Ended June 30, 2014	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2013	$ 350	$ 112	$ 465	$ 15	$ 942
Total realized / unrealized gains (losses)					
Included in net income	3		(360)[(a)]		(357)
Included in noncurrent payables to affiliates	11				11
Included in payable for Zion Station decommissioning		4			4
Change in collateral			178		178
Purchases, sales, issuances and settlements					
Purchases	249	42	15	2	308
Sales	(2)	(25)	(6)		(33)
Settlements	(19)				(19)
Transfers into Level 3			(30)		(30)
Transfers out of Level 3			(20)	(7)	(27)
Balance as of June 30, 2014	$ 592	$ 133	$ 242	$ 10	$ 977

The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the six months ended June 30, 2014	$	2	$		$	(427)	$		$ (425)

(a) Includes an increase for the reclassification of $67 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and six months ended June 30, 2014, respectively.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Three Months Ended June 30, 2013	**Nuclear Decommissioning Trust Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total**
Balance as of March 31, 2013	$ 210	$ 104	$ 420	$ 9	$ 743
Total realized / unrealized gains (losses)					
Included in net income	1		168[(a)(b)]		169
Included in other comprehensive income			(95)[(b)]		(95)
Included in noncurrent payables to affiliates	8				8
Included in payable for Zion Station decommissioning		1			1
Changes in collateral			10		10
Purchases, sales, issuances and settlements					
Purchases	35	11	13	2	61
Sales	(11)	(5)	(4)		(20)
Settlements	(3)				(3)
Transfers into Level 3			3		3
Transfers out of Level 3			1		1
Balance as of June 30, 2013	$ 240	$ 111	$ 516	$ 11	$ 878
The amount of total losses included in income attributed to the change in unrealized losses related to assets and liabilities held for the three months ended June 30, 2013	$ 1	$	$ 183	$	$ 184

Six Months Ended June 30, 2013	**Nuclear Decommissioning Trust Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total**
Balance as of December 31, 2012	$ 183	$ 89	$ 660	$ 17	$ 949
Total realized / unrealized gains (losses)					
Included in net income	2		24[(a)(b)]		26
Included in other comprehensive income			(219)[(b)]		(219)
Included in noncurrent payables to affiliates	9				9
Included in payable for Zion Station decommissioning		1			1
Changes in collateral			43		43
Purchases, sales, issuances and settlements					
Purchases	67	33	8[(c)]	2	110
Sales	(13)	(12)	(8)	(8)	(41)
Settlements	(8)				(8)
Transfers into Level 3			7		7
Transfers out of Level 3			1		1
Balance as of June 30, 2013	$ 240	$ 111	$ 516	$ 11	$ 878
The amount of total gains included in income attributed to the change in unrealized gains related to	$ 1	$	$ 97	$	$ 98

assets and liabilities held for the six months ended
June 30, 2013

(a) Includes the reclassification of $15 million and $73 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and six months ended June 30, 2013, respectively.
(b) Includes $3 million of decreases in fair value and $11 million of increases in fair value and realized losses due to settlements of $82 million and $215 million associated with Generation s financial swap contract with ComEd for the three and six months ended June 30, 2013, respectively. This position eliminates upon consolidation in Exelon s Consolidated Financial Statements.
(c) Includes $10 million which Generation was paid to enter into out of the money purchase contracts.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

	Operating Revenue	Purchased Power and Fuel	Other, net[(a)]
Total gains (losses) included in net income for the three months ended June 30, 2014	$ (62)	$ 14	$ 2
Total losses included in net income for the six months ended June 30, 2014	$ (330)	$ (30)	$ 3
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2014	$ (10)	$ 29	$ 2
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2014	$ (435)	$ 8	$ 2

	Operating Revenue	Purchased Power and Fuel	Other, net[(a)]
Total gains included in net income for the three months ended June 30, 2013	$ 148	$ 20	$ 1
Total gains (losses) included in net income for the six months ended June 30, 2013	$ (28)	$ 52	$ 2
Change in the unrealized gains relating to assets and liabilities held for the three months ended June 30, 2013	$ 153	$ 30	$ 1
Change in the unrealized gains relating to assets and liabilities held for the nine months ended June 30, 2013	$ 29	$ 68	$ 1

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

ComEd

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

As of June 30, 2014	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Rabbi trust investments				
Mutual funds	$ 1	$	$	$ 1
Rabbi trust investments subtotal	1			1
Total assets	$ 1	$	$	$ 1
Liabilities				
Deferred compensation obligation		(8)		(8)

Mark-to-market derivative liabilities[(a)]			(134)	(134)
Total liabilities		(8)	(134)	(142)
Total net assets (liabilities)	$ 1	$ (8)	$ (134)	$ (141)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Rabbi trust investments				
Mutual funds	$ 5	$	$	$ 5
Rabbi trust investments subtotal	5			5
Total assets	5			5
Liabilities				
Deferred compensation obligation		(8)		(8)
Mark-to-market derivative liabilities[(a)]			(193)	(193)
Total liabilities		(8)	(193)	(201)
Total net assets (liabilities)	$ 5	$ (8)	$ (193)	$ (196)

(a) The Level 3 balance includes the current and noncurrent liability of $13 million and $121 million at June 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.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2014 and 2013:

Three Months Ended June 30, 2014	Mark-to-Market Derivatives
Balance as of March 31, 2014	$ (168)
Total realized / unrealized gains included in regulatory assets[(a)]	34
Balance as of June 30, 2014	$ (134)

Six Months Ended June 30, 2014	Mark-to-Market Derivatives
Balance as of December 31, 2013	$ (193)
Total realized / unrealized gains included in regulatory assets[(b)]	59
Balance as of June 30, 2014	$ (134)

(a) Includes $34 million decreases in the fair value partially offset by immaterial realized losses due to settlements recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended June 30, 2014.

(b) Includes $64 million of decreases in the fair value partially offset by realized gains due to settlements of $5 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the six months ended June 30, 2014.

Three Months Ended June 30, 2013	Mark-to-Market Derivatives	
Balance as of March 31, 2013	$	(160)
Total realized / unrealized gains included in regulatory assets[(a)(b)]		75
Balance as of June 30, 2013	$	(85)

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Six Months Ended June 30, 2013	**Mark-to-Market Derivatives**
Balance as of December 31, 2012	$ (293)
Total realized / unrealized gains included in regulatory assets[a][b]	208
Balance as of June 30, 2013	$ (85)

(a) Includes $3 million of increases in fair value and $11 million of decreases in fair value and realized gains due to settlements of $82 million and $215 million of associated with ComEd s financial swap contract with Generation for the three and six months ended June 30, 2013, respectively. All items eliminate upon consolidation in Exelon s Consolidated Financial Statements.

(b) Includes $9 million and $20 million of increases in the fair value and realized losses due to settlements of $1 million and $4 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three and six months ended June 30, 2013, respectively.

PECO

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

As of June 30, 2014	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$ 50	$	$	$ 50
Rabbi trust investments[a]				
Mutual funds	9			9
Rabbi trust investments subtotal	9			9
Total assets	59			59
Liabilities				
Deferred compensation obligation		(15)		(15)
Total liabilities		(15)		(15)
Total net assets (liabilities)	$ 59	$ (15)	$	$ 44

As of December 31, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$ 175	$	$	$ 175
Rabbi trust investments[a]				
Mutual funds	9			9

Rabbi trust investments subtotal	9			9
Total assets	184			184
Liabilities				
Deferred compensation obligation		(17)		(17)
Total liabilities		(17)		(17)
Total net assets (liabilities)	$ 184	$ (17)	$	$ 167

(a) Excludes $14 million of the cash surrender value of life insurance investments at both June 30, 2014 and December 31, 2013.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

PECO had no Level 3 assets or liabilities measured at fair value on a recurring basis during the six months ended June 30, 2014 and 2013.

BGE

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

As of June 30, 2014	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$ 53	$	$	$ 53
Rabbi trust investments				
Mutual funds	5			5
Rabbi trust investments subtotal	5			5
Total assets	58			58
Liabilities				
Deferred compensation obligation		(5)		(5)
Total liabilities		(5)		(5)
Total net assets (liabilities)	$ 58	$ (5)	$	$ 53

As of December 31, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$ 31	$	$	$ 31
Rabbi trust investments				
Mutual funds	6			6
Rabbi trust investments subtotal	6			6
Total assets	37			37
Liabilities				
Deferred compensation obligation		(6)		(6)
Total liabilities		(6)		(6)
Total net assets (liabilities)	$ 37	$ (6)	$	$ 31

BGE had no Level 3 assets or liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2014 and 2013.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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. Comingled 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 June 30, 2014, Generation has outstanding commitments to invest in middle market lending, corporate debt securities, private equity investments, and real estate investments of approximately $430 million. These commitments will be funded by Generation s existing nuclear decommissioning trust funds.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 is generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument s market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $2.57 and $0.41 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3. 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 June 30, 2014[c]	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives Economic Hedges (Generation)[a]	$ 82	Discounted Cash Flow	Forward power price	$16 - $170(d)
			Forward gas price	$2.19 - $19.84(d)
		Option Model	Volatility percentage	8% - 260%
Mark-to-market derivatives Proprietary trading (Generation)[a]	$ 8	Discounted Cash Flow	Forward power price	$13 - $168(d)
		Option Model	Volatility percentage	8% - 260%
Mark-to-market derivatives (ComEd)	$ (134)	Discounted Cash Flow	Forward heat rate[b]	8x - 9x
			Marketability reserve	3.5% - 8%
			Renewable factor	86% - 123%

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 $152 million as of June 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 $106 and $10.29, respectively, and would be approximately $93 for power proprietary trading.

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

Type of trade	Fair Value at December 31, 2013[c]	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives Economic Hedges (Generation)[a]	$ 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]	$ 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation s owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of June 30, 2014, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 75%-78%, and 46%-49% 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 represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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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 2013 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 2013 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 2,629 GWhs and 5,123 GWhs for the three and six months ended June 30, 2014, respectively, and 1,995 GWhs and 3,567 for the three and six months ended June 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.

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 June 30, 2014, Exelon and Generation had $1,550 million and $700 million of notional amounts of fixed-to-floating hedges outstanding, respectively, and $1,111 million and $411 million of notional amounts of floating-to-fixed hedges outstanding, respectively.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 $4 million decrease in Exelon Consolidated pre-tax income for the six months ended June 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 June 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**	**Total**
Mark-to-market derivative assets (current assets)	$	$ 2	$ 14	$ (18)	$ (2)	$	$ (2)
Mark-to-market derivative assets (noncurrent assets)	16	2	12	(10)	20	18	38
Total mark-to-market derivative assets	$ 16	$ 4	$ 26	$ (28)	$ 18	$ 18	$ 36
Mark-to-market derivative liabilities (current liabilities)	$ (1)	$ (4)	$ (15)	$ 19	$ (1)	$	$ (1)
Mark-to-market derivative liabilities (noncurrent liabilities)	(19)	(2)	(11)	11	(21)	(6)	(27)
Total mark-to-market derivative liabilities	$ (20)	$ (6)	$ (26)	$ 30	$ (22)	$ (6)	$ (28)
Total mark-to-market derivative net assets (liabilities)	$ (4)	$ (2)	$	$ 2	$ (4)	$ 12	$ 8

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

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

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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						Exelon
Description	**Derivatives Designated as Hedging Instruments**	**Economic Hedges**	**Proprietary Trading[a]**	**Collateral and Netting[b]**	**Subtotal**	**Other 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:

	Income Statement	Three Months Ended June 30,			
		2014	2013	2014	2013
	Location	Gain (Loss) on Swaps		Gain (Loss) on Borrowings	
Generation	Interest expense[a]	$ (3)	$ (5)	$ 2	$ 2
Exelon	Interest expense	3	(6)	(3)	3

	Income Statement	Six Months Ended June 30,			
		2014	2013	2014	2013
		Gain (Loss) on Swaps		Gain (Loss) on Borrowings	

	Location				
Generation	Interest expense[a]	$ (8)	$ (9)	$ 1	$ 1
Exelon	Interest expense	5	(12)	(7)	4

(a) For the three and six months ended June 30, 2014, the loss on Generation swaps included $4 million and $8 million realized in earnings, respectively, with an immaterial amount excluded from hedge effectiveness testing. For the three and six months ended June 30, 2013, the loss on Generation swaps included $4 million and $8 million realized in earnings, respectively, with an immaterial amount excluded from hedge effectiveness testing.

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During the first six months of 2014, Exelon entered into $50 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 June 30, 2014, Exelon and Generation had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $1,400 million and $550 million, with unrealized gains of $33 million and $16 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 unrealized gains of $26 million and $23 million, respectively. During the three and six months ended June 30, 2014, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $5 million and a $8 million gain, respectively. During the three and six months ended June 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 a notional amount of $485 million and a mandatory early termination date of September 30, 2014. The swap hedges approximately 75% of Generation s future interest rate exposure associated with the financing and was designated as a cash flow hedge. As such, the effective portion of the hedge is recorded in other comprehensive income within Generation s Consolidated Balance Sheets, with any ineffectiveness recorded in Generation s Consolidated Statements of Operations and Comprehensive Income. Net gains (or losses) from settlement of the hedges, to the extent effective, are amortized as an adjustment to the interest expense over the term of the DOE guaranteed loan.

Every time Generation draws down on the loan, an offsetting hedge (fixed-to-floating) is executed and a portion of the cash flow hedge with a notional amount equal to the offsetting hedge, is de-designated and the related gains or losses going forward are reflected in earnings, which are largely offset by the losses or gains in the offsetting hedge.

Antelope Valley received its first loan advance on April 5, 2012, and a series of additional advances subsequently. Generation has entered into a series of fixed-to-floating interest rate swaps with an aggregated notional amount of $350 million, approximately 75% of the loan advance amount to offset portions of the original interest rate hedge, which are not designated as cash flow hedges. The remaining cash flow hedge has a notional amount of $135 million. At June 30, 2014, Generation s mark-to-market derivative liability relating to the interest rate swaps in connection with the loan agreement to fund Antelope Valley was $15 million.

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 $27 million as of June 30, 2014 and expire in 2027. After the closing of the merger with Constellation, the swaps were re-designated as cash flow hedges. At June 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 June 30, 2014 and expires in 2030. This swap is designated as a cash flow hedge. At June 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 $223 million as of June 30, 2014 and expire in 2020. The swaps are designated as cash flow hedges. At June 30, 2014, the subsidiary had a $2 million derivative liability related to the swaps.

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During the first six months of 2014, Exelon entered into $400 million of floating-to-fixed interest rate hedges to refinance existing debt. The swaps are designated as cash flow hedges. At June 30, 2014, Exelon had a $6 million derivative liability related to the swaps.

During the three and six months ended June 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 second quarter of 2014, Exelon entered into $300 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 June 30, 2014, Exelon had an immaterial derivative asset related to the swaps.

At June 30, 2014, Exelon and Generation had $150 million in notional amounts of fixed-to-floating interest rate swaps that are marked-to-market, with unrealized gains of $1 million. These swaps, which were acquired as part of the merger with Constellation, expire in 2014. During the six months ended June 30, 2014 and 2013, the impact on the results of operations was immaterial.

At June 30, 2014, Generation had $257 million in notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $121 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 June 30, 2014 and December 31, 2013, $7 million of cash collateral held 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 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.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of June 30, 2014:

Derivatives	Generation Economic Hedges	Generation Proprietary Trading	Generation Collateral and Netting[a]	Generation Subtotal[b]	ComEd Economic Hedges[c]	Exelon Total Derivatives
Mark-to-market derivative assets (current assets)	$ 3,422	$ 925	$ (3,716)	$ 631	$	$ 631
Mark-to-market derivative assets (noncurrent assets)	1,394	149	(1,099)	444		444
Total mark-to-market derivative assets	$ 4,816	$ 1,074	$ (4,815)	$ 1,075	$	$ 1,075
Mark-to-market derivative liabilities (current liabilities)	$ (3,354)	$ (900)	$ 4,040	$ (214)	$ (13)	$ (227)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,214)	(165)	1,265	(114)	(121)	(235)
Total mark-to-market derivative liabilities	$ (4,568)	$ (1,065)	$ 5,305	$ (328)	$ (134)	$ (462)
Total mark-to-market derivative net assets (liabilities)	$ 248	$ 9	$ 490	$ 747	$ (134)	$ 613

(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 $(126) million and $(56) million, respectively, and current and noncurrent liabilities are shown net of collateral of $(198) million and $(110) million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $490 million at June 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:

Description	Generation Economic Hedges	Generation Proprietary Trading	Generation Collateral and Netting[a]	Generation Subtotal[b]	ComEd Economic Hedges[c]	Exelon 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

(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.

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

(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 received, net of cash collateral posted 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 $94 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 June 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	
		Generation	Exelon Total Cash
Three Months Ended June 30, 2014	**Income Statement Location**	**Energy-Related Hedges**	**Flow Hedges**
Accumulated OCI derivative gain at March 31, 2014		$ 95[a]	$ 95
Effective portion of changes in fair value			(10)
Reclassifications from accumulated OCI to net income	Operating Revenues	(38)[b]	(38)
Accumulated OCI derivative gain at June 30, 2014		$ 57[a]	$ 47

(a) Excludes $6 million and $3 million of gains, net of taxes, related to interest rate swaps and treasury rate locks as of June 30, 2014 and March 31, 2014.