EXELON CORP
Form 10-Q
November 07, 2013

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 September 30, 2013

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	36-0938600

	(an Illinois corporation) 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210

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 September 30, 2013 was:

Exelon Corporation Common Stock, without par value	856,903,972
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,855

PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000

TABLE OF CONTENTS

1

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.
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 2012 Form 10-K	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2012 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
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
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

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTC	Competitive Transition Charge
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
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

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
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
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
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

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

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
SFC	Supplier Forward Contract
SGIG	Smart Grid Investment Grant
SGIP	Smart Grid Initiative Program
SILO	Sale-In, Lease-Out
SMP	Smart Meter Program
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
TEG	Termoelectrica del Golfo
TEP	Termoelectrica Penoles
Upstream	Natural gas exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

FILING FORMAT

This combined Form 10-Q is being filed separately by 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 2012 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 19; (2) this Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors, (b) Part 1, Financial Information, ITEM 2. Management s Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

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

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	**2013**	**2012**	**2013**	**2012**
Operating revenues	$ 6,502	$ 6,579	$ 18,725	$ 17,235
Operating expenses				
Purchased power and fuel	2,743	3,026	8,143	7,398
Operating and maintenance	1,735	2,170	5,391	5,979
Depreciation and amortization	530	500	1,606	1,376
Taxes other than income	277	290	825	737
Total operating expenses	5,285	5,986	15,965	15,490
Equity in earnings (loss) of unconsolidated affiliates	37	10	7	(69)
Operating income	1,254	603	2,767	1,676
Other income and (deductions)				
Interest expense	(228)	(240)	(1,091)	(678)
Interest expense to affiliates, net	(6)	(6)	(19)	(19)
Other, net	155	101	311	253
Total other income and (deductions)	(79)	(145)	(799)	(444)
Income before income taxes	1,175	458	1,968	1,232
Income taxes	439	161	733	445
Net income	736	297	1,235	787
Net income (loss) attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	(2)	1	11	5
Net income attributable to common shareholders	738	296	1,224	782
Comprehensive income (loss), net of income taxes				
Net income	736	297	1,235	787
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	1			1
Actuarial loss reclassified to periodic cost	49	44	151	126
Transition obligation reclassified to periodic cost				2
Pension and non-pension postretirement benefit plans valuation adjustment	(8)	(67)	69	(78)
Deferred compensation unit valuation adjustment			10	
Change in unrealized loss on cash flow hedges	(46)	(88)	(169)	(29)
Change in unrealized income on equity investments	16	17	51	23
Change in unrealized gain (loss) on foreign currency translation		2	(5)	
Change in unrealized loss on marketable securities			(1)	
Other comprehensive income (loss)	12	(92)	106	45
Comprehensive income	$ 748	$ 205	$ 1,341	$ 832

Average shares of common stock outstanding:				
Basic	857	854	856	804
Diluted	860	857	860	806
Earnings per average common share:				
Basic	$ 0.86	$ 0.35	$ 1.43	$ 0.97
Diluted	$ 0.86	$ 0.35	$ 1.42	$ 0.97
Dividends per common share	$ 0.31	$ 0.53	$ 1.15	$ 1.58

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Nine Months Ended September 30, 2013	2012
Cash flows from operating activities		
Net income	$ 1,235	$ 787
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	2,844	2,909
Impairment of assets held for sale		278
Deferred income taxes and amortization of investment tax credits	(164)	263
Net fair value changes related to derivatives	(229)	(377)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(95)	(142)
Other non-cash operating activities	738	1,235
Changes in assets and liabilities:		
Accounts receivable	54	228
Inventories	(103)	12
Accounts payable, accrued expenses and other current liabilities	(243)	(817)
Option premiums paid, net	(38)	(122)
Counterparty collateral (posted) received, net	(73)	408
Income taxes	863	465
Pension and non-pension postretirement benefit contributions	(360)	(131)
Other assets and liabilities	(35)	(422)
Net cash flows provided by operating activities	4,394	4,574
Cash flows from investing activities		
Capital expenditures	(3,887)	(4,162)
Proceeds from nuclear decommissioning trust fund sales	3,344	6,262
Investment in nuclear decommissioning trust funds	(3,518)	(6,422)
Cash and restricted cash acquired from Constellation		964
Proceeds from sale of long-lived assets	32	
Proceeds from sales of investments	20	26
Purchases of investments	(3)	(13)
Change in restricted cash	(23)	(38)
Other investing activities	65	41
Net cash flows used in investing activities	(3,970)	(3,342)
Cash flows from financing activities		
Payment of accounts receivable agreement	(210)	
Changes in short-term debt	205	(139)
Issuance of long-term debt	2,031	1,558
Retirement of long-term debt	(1,156)	(731)
Redemption of preferred securities	(93)	
Dividends paid on common stock	(981)	(1,226)
Dividends paid to former Constellation shareholders		(51)
Proceeds from employee stock plans	40	61
Other financing activities	(102)	(20)
Net cash flows used in financing activities	(266)	(548)

Increase in cash and cash equivalents	158	684
Cash and cash equivalents at beginning of period	1,486	1,016
Cash and cash equivalents at end of period	$ 1,644	$ 1,700

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,600	$ 1,411
Cash and cash equivalents of variable interest entities	44	75
Restricted cash and investments	60	86
Restricted cash and investments of variable interest entities	87	47
Accounts receivable, net		
Customer ($0 and $289 gross accounts receivable pledged as collateral as of September 30, 2013 and December 31, 2012, respectively)	2,584	2,795
Other	1,232	1,141
Accounts receivable, net, variable interest entities	177	292
Mark-to-market derivative assets	730	938
Unamortized energy contract assets	460	886
Inventories, net		
Fossil fuel	288	246
Materials and supplies	821	768
Deferred income taxes	292	131
Regulatory assets	877	764
Other	699	560
Total current assets	9,951	10,140
Property, plant and equipment, net	46,495	45,186
Deferred debits and other assets		
Regulatory assets	6,509	6,497
Nuclear decommissioning trust funds	7,776	7,248
Investments	1,154	1,184
Investments in affiliates	23	22
Investment in CENG	1,939	1,849
Goodwill	2,625	2,625
Mark-to-market derivative assets	779	937
Unamortized energy contracts assets	803	1,073
Pledged assets for Zion Station decommissioning	486	614
Other	1,121	1,186
Total deferred debits and other assets	23,215	23,235
Total assets	$ 79,661	$ 78,561

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 214	$
Short-term notes payable accounts receivable agreement		210
Long-term debt due within one year	1,461	975
Long-term debt due within one year of variable interest entities	182	72
Accounts payable	2,369	2,446
Accounts payable of variable interest entities	108	202
Accrued expenses	1,540	1,800
Deferred income taxes	50	58
Regulatory liabilities	314	368
Mark-to-market derivative liabilities	126	352
Unamortized energy contract liabilities	305	455
Other	838	853
Total current liabilities	7,507	7,791
Long-term debt	17,583	17,190
Long-term debt to financing trusts	648	648
Long-term debt of variable interest entities	339	508
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	11,931	11,551
Asset retirement obligations	5,118	5,074
Pension obligations	3,094	3,428
Non-pension postretirement benefit obligations	2,764	2,662
Spent nuclear fuel obligation	1,021	1,020
Regulatory liabilities	4,204	3,981
Mark-to-market derivative liabilities	218	281
Unamortized energy contract liabilities	314	528
Payable for Zion Station decommissioning	339	432
Other	2,514	1,650
Total deferred credits and other liabilities	31,517	30,607
Total liabilities	57,594	56,744
Commitments and contingencies		
Preferred securities of subsidiary		87
Shareholders equity		
Common stock (No par value, 2,000 shares authorized, 857 shares and 855 shares outstanding at September 30, 2013 and December 31, 2012, respectively)	16,716	16,632
Treasury stock, at cost (35 shares at September 30, 2013 and December 31, 2012, respectively)	(2,327)	(2,327)
Retained earnings	10,131	9,893
Accumulated other comprehensive loss, net	(2,661)	(2,767)
Total shareholders equity	21,859	21,431
BGE preference stock not subject to mandatory redemption	193	193
Noncontrolling interest	15	106

Total equity		22,067		21,730
Total liabilities and shareholders equity	$	79,661	$	78,561

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Non-controlling Interest	Preferred and Preference Stock	Total Equity
Balance, December 31, 2012	889,525	$ 16,632	$ (2,327)	$ 9,893	$ (2,767)	$ 106	$ 193	$ 21,730
Net income (loss)				1,224		(6)	17	1,235
Long-term incentive plan activity	2,122	84						84
Common stock dividends				(986)				(986)
Impairment of long-lived assets						(4)		(4)
Consolidated VIE dividend to non-controlling interest						(63)		(63)
Deconsolidation of VIE						(18)		(18)
Redemption of preferred securities							(6)	(6)
Preferred and preference stock dividends							(11)	(11)
Other comprehensive income net of income taxes of $(70)					106			106
Balance, September 30, 2013	891,647	$ 16,716	$ (2,327)	$ 10,131	$ (2,661)	$ 15	$ 193	$ 22,067

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Operating revenues				
Operating revenues	$ 3,871	$ 3,558	$ 10,729	$ 9,276
Operating revenues from affiliates	384	473	1,129	1,263
Total operating revenues	4,255	4,031	11,858	10,539
Operating expenses				
Purchased power and fuel	2,179	2,122	6,294	5,018
Operating and maintenance	936	1,289	2,943	3,319
Operating and maintenance from affiliates	140	140	434	467
Depreciation and amortization	218	207	643	564
Taxes other than income	98	109	292	272
Total operating expenses	3,571	3,867	10,606	9,640
Equity in earnings (loss) of unconsolidated affiliates	37	10	7	(69)
Operating income	721	174	1,259	830
Other income and (deductions)				
Interest expense	(82)	(85)	(257)	(223)
Other, net	134	83	229	185
Total other income and (deductions)	52	(2)	(28)	(38)
Income before income taxes	773	172	1,231	792
Income taxes	288	85	436	373
Net income	485	87	795	419
Net loss attributable to noncontrolling interests	(5)	(4)	(6)	(6)
Net income attributable to membership interest	490	91	801	425
Comprehensive income (loss), net of income taxes				
Net income	485	87	795	419
Other comprehensive (loss) income, net of income taxes				
Change in unrealized loss on cash flow hedges	(49)	(171)	(316)	(185)
Change in unrealized income on equity investments	16	17	52	23
Change in unrealized income (loss) on foreign currency translation	1	2	(5)	
Change in unrealized loss on marketable securities			(1)	(1)
Other comprehensive loss	(32)	(152)	(270)	(163)
Comprehensive income (loss)	$ 453	$ (65)	$ 525	$ 256

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	**Nine Months Ended September 30, 2013**	**2012**
Cash flows from operating activities		
Net income	$ 795	$ 419
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	1,937	2,178
Impairment on assets held for sale		278
Deferred income taxes and amortization of investment tax credits	183	69
Net fair value changes related to derivatives	(222)	(345)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(95)	(142)
Other non-cash operating activities	375	422
Changes in assets and liabilities:		
Accounts receivable	57	189
Receivables from and payables to affiliates, net	2	(58)
Inventories	(81)	34
Accounts payable, accrued expenses and other current liabilities	(162)	(546)
Option premiums paid, net	(38)	(122)
Counterparty collateral (paid) received, net	(123)	315
Income taxes	315	565
Pension and non-pension postretirement benefit contributions	(123)	(48)
Other assets and liabilities	(163)	(195)
Net cash flows provided by operating activities	2,657	3,013
Cash flows from investing activities		
Capital expenditures	(1,995)	(2,602)
Proceeds from nuclear decommissioning trust fund sales	3,344	6,262
Investment in nuclear decommissioning trust funds	(3,518)	(6,422)
Change in restricted cash	(30)	
Proceeds from sale of long-lived assets	32	
Cash acquired from Constellation		708
Other investing activities	18	(2)
Net cash flows used in investing activities	(2,149)	(2,056)
Cash flows from financing activities		
Issuance of long-term debt	831	957
Retirement of long-term debt	(471)	(138)
Change in short-term debt	12	(41)
Distribution to member	(550)	(1,384)
Other financing activities	(73)	(17)
Net cash flows used in financing activities	(251)	(623)
Increase in cash and cash equivalents	257	334
Cash and cash equivalents at beginning of period	671	496
Cash and cash equivalents at end of period	$ 928	$ 830

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 884	$ 596
Cash and cash equivalents of variable interest entities	44	75
Restricted cash and cash equivalents of variable interest entities	37	16
Accounts receivable, net		
Customer	1,489	1,482
Other	417	472
Accounts receivable, net, variable interest entities	175	292
Mark-to-market derivative assets	730	938
Mark-to-market derivative assets with affiliates		226
Receivables from affiliates	107	141
Unamortized energy contract assets	460	886
Inventories, net		
Fossil fuel	169	130
Materials and supplies	661	626
Deferred income taxes	177	
Other	455	331
Total current assets	5,805	6,211
Property, plant and equipment, net	19,797	19,531
Deferred debits and other assets		
Nuclear decommissioning trust funds	7,776	7,248
Investments	401	420
Investment in CENG	1,939	1,849
Mark-to-market derivative assets	766	924
Prepaid pension asset	1,927	1,975
Pledged assets for Zion Station decommissioning	486	614
Unamortized energy contract assets	803	1,073
Other	798	836
Total deferred debits and other assets	14,896	14,939
Total assets	$ 40,498	$ 40,681

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 21	$
Long-term debt due within one year	544	24
Long-term debt due within one year of variable interest entities	104	4
Accounts payable	1,254	1,346
Accounts payable of variable interest entities	108	202
Accrued expenses	925	1,116
Payables to affiliates	162	193
Deferred income taxes	44	128
Mark-to-market derivative liabilities	110	334
Unamortized energy contract liabilities	276	378
Other	348	372
Total current liabilities	3,896	4,097
Long-term debt	5,545	5,245
Long-term debt to affiliate	1,528	2,007
Long-term debt of variable interest entities	88	203
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,899	5,398
Asset retirement obligations	4,983	4,938
Non-pension postretirement benefit obligations	843	755
Spent nuclear fuel obligation	1,021	1,020
Payables to affiliates	2,593	2,397
Mark-to-market derivative liabilities	112	232
Unamortized energy contract liabilities	311	516
Payable for Zion Station decommissioning	339	432
Other	789	776
Total deferred credits and other liabilities	16,890	16,464
Total liabilities	27,947	28,016
Commitments and contingencies		
Equity		
Member s equity		
Membership interest	8,872	8,876
Undistributed earnings	3,419	3,168
Accumulated other comprehensive income, net	243	513
Total member s equity	12,534	12,557
Noncontrolling interest	17	108
Total equity	12,551	12,665
Total liabilities and equity	$ 40,498	$ 40,681

See the Combined Notes to Consolidated Financial Statements

17

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(Unaudited)

	Member s Equity				
(In millions)	**Membership Interest**	**Undistributed Earnings**	**Accumulated Other Comprehensive Income, net**	**Noncontrolling Interest**	**Total Equity**
Balance, December 31, 2012	$ 8,876	$ 3,168	$ 513	$ 108	$ 12,665
Net income (loss)		801		(6)	795
Noncontrolling interest acquired	(3)				(3)
Distribution to member		(550)			(550)
Consolidated VIE dividend to non-controlling interest				(63)	(63)
Deconsolidation of VIE	(1)			(18)	(19)
Impairment of long-lived assets				(4)	(4)
Other comprehensive loss, net of income taxes of $177			(270)		(270)
Balance, September 30, 2013	$ 8,872	$ 3,419	$ 243	$ 17	$ 12,551

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Operating revenues				
Operating revenues	$ 1,155	$ 1,484	$ 3,393	$ 4,152
Operating revenues from affiliates	1		2	2
Total operating revenues	1,156	1,484	3,395	4,154
Operating expenses				
Purchased power	158	498	522	1,255
Purchased power from affiliate	143	180	409	631
Operating and maintenance	296	313	907	882
Operating and maintenance from affiliate	37	37	113	118
Depreciation and amortization	164	157	501	458
Taxes other than income	80	81	225	224
Total operating expenses	878	1,266	2,677	3,568
Operating income	278	218	718	586
Other income and (deductions)				
Interest expense	(71)	(71)	(493)	(221)
Interest expense to affiliates, net	(3)	(3)	(10)	(9)
Other, net	7	5	18	12
Total other income and (deductions)	(67)	(69)	(485)	(218)
Income before income taxes	211	149	233	368
Income taxes	85	59	93	149
Net income	126	90	140	219
Other comprehensive income, net of income taxes				
Change in unrealized gain on marketable securities				1
Other comprehensive income				1
Comprehensive income	$ 126	$ 90	$ 140	$ 220

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	**Nine Months Ended September 30, 2013**	**2012**
Cash flows from operating activities		
Net income	$ 140	$ 219
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	501	458
Deferred income taxes and amortization of investment tax credits	(152)	198
Other non-cash operating activities	26	310
Changes in assets and liabilities:		
Accounts receivable	(21)	22
Receivables from and payables to affiliates, net	(32)	(32)
Inventories	(12)	(11)
Accounts payable, accrued expenses and other current liabilities	48	(49)
Counterparty collateral received, net	50	93
Income taxes	262	116
Pension and non-pension postretirement benefit contributions	(120)	(19)
Other assets and liabilities	160	(124)
Net cash flows provided by operating activities	850	1,181
Cash flows from investing activities		
Capital expenditures	(1,074)	(896)
Proceeds from sales of investments	5	26
Purchases of investments	(3)	(13)
Change in restricted cash	(3)	
Other investing activities	33	12
Net cash flows used in investing activities	(1,042)	(871)
Cash flows from financing activities		
Changes in short-term debt	153	35
Issuance of long-term debt	350	
Retirement of long-term debt	(252)	(450)
Dividends paid on common stock	(165)	(95)
Other financing activities	(4)	(3)
Net cash flows provided by (used in) financing activities	82	(513)
Decrease in cash and cash equivalents	(110)	(203)
Cash and cash equivalents at beginning of period	144	234
Cash and cash equivalents at end of period	$ 34	$ 31

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 34	$ 144
Restricted cash	3	
Accounts receivable, net		
Customer	443	539
Other	525	452
Inventories, net	103	91
Deferred income taxes	18	83
Counterparty collateral deposited	3	53
Regulatory assets	335	388
Other	31	25
Total current assets	1,495	1,775
Property, plant and equipment, net	14,444	13,826
Deferred debits and other assets		
Regulatory assets	819	666
Investments	5	8
Investments in affiliates	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,361	2,039
Prepaid pension asset	1,631	1,661
Other	300	299
Total deferred debits and other assets	7,747	7,304
Total assets	$ 23,686	$ 22,905

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 153	$
Long-term debt due within one year	617	252
Accounts payable	474	379
Accrued expenses	238	295
Payables to affiliates	61	97
Customer deposits	133	136
Regulatory liabilities	171	170
Mark-to-market derivative liability	16	18
Mark-to-market derivative liability with affiliate		226
Other	84	82
Total current liabilities	1,947	1,655
Long-term debt	5,057	5,315
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,057	4,272
Asset retirement obligations	99	99
Non-pension postretirement benefits obligations	354	273
Regulatory liabilities	3,393	3,229
Mark-to-market derivative liability	106	49
Other	994	484
Total deferred credits and other liabilities	9,003	8,406
Total liabilities	16,213	15,582
Commitments and contingencies		
Shareholders equity		
Common stock	1,588	1,588
Other paid-in capital	5,189	5,014
Retained earnings	696	721
Total shareholders equity	7,473	7,323
Total liabilities and shareholders equity	$ 23,686	$ 22,905

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Accumulated Other Comprehensive Income, net	Total Shareholders Equity
Balance, December 31, 2012	$ 1,588	$ 5,014	$ (1,639)	$ 2,360	$	$ 7,323
Net income			140			140
Appropriation of retained earnings for future dividends			(140)	140		
Common stock dividends				(165)		(165)
Parent tax matter indemnification		175				175
Balance, September 30, 2013	$ 1,588	$ 5,189	$ (1,639)	$ 2,335	$	$ 7,473

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	**2013**	**2012**	**2013**	**2012**
Operating revenues				
Operating revenues	$ 727	$ 805	$ 2,294	$ 2,393
Operating revenues from affiliates	1	1	1	3
Total operating revenues	728	806	2,295	2,396
Operating expenses				
Purchased power and fuel	207	155	632	626
Purchased power from affiliate	82	171	321	407
Operating and maintenance	162	172	480	491
Operating and maintenance from affiliates	24	27	74	83
Depreciation and amortization	57	55	171	161
Taxes other than income	41	48	121	122
Total operating expenses	573	628	1,799	1,890
Operating income	155	178	496	506
Other income and (deductions)				
Interest expense	(26)	(29)	(77)	(85)
Interest expense to affiliates, net	(3)	(3)	(9)	(9)
Other, net	1	2	4	6
Total other income and (deductions)	(28)	(30)	(82)	(88)
Income before income taxes	127	148	414	418
Income taxes	35	25	122	118
Net income	92	123	292	300
Preferred security dividends and redemption		1	7	3
Net income attributable to common shareholder	92	122	285	297
Comprehensive income, net of income taxes				
Net income	92	123	292	300
Other comprehensive income, net of income taxes				
Change in unrealized gains on marketable securities				1
Other comprehensive income				1
Comprehensive income	$ 92	$ 123	$ 292	$ 301

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Nine Months Ended September 30, 2013	2012
Cash flows from operating activities		
Net income	$ 292	$ 300
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	171	161
Deferred income taxes and amortization of investment tax credits	35	27
Other non-cash operating activities	84	96
Changes in assets and liabilities:		
Accounts receivable	41	36
Receivables from and payables to affiliates, net	(25)	15
Inventories	4	10
Accounts payable, accrued expenses and other current liabilities	9	(75)
Income taxes	66	127
Pension and non-pension postretirement benefit contributions	(10)	(12)
Other assets and liabilities	(47)	(57)
Net cash flows provided by operating activities	620	628
Cash flows from investing activities		
Capital expenditures	(374)	(274)
Changes in intercompany money pool	(1)	5
Change in restricted cash	(1)	2
Other investing activities	8	8
Net cash flows used in investing activities	(368)	(259)
Cash flows from financing activities		
Payment of accounts receivable agreement	(210)	
Issuance of long-term debt	550	350
Dividends paid on common stock	(248)	(258)
Dividends paid on preferred securities	(1)	(3)
Redemption of preferred securities	(93)	
Other financing activities	(3)	(4)
Net cash flows (used in) provided by financing activities	(5)	85
Increase in cash and cash equivalents	247	454
Cash and cash equivalents at beginning of period	362	194
Cash and cash equivalents at end of period	$ 609	$ 648

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 609	$ 362
Restricted cash and cash equivalents	1	
Accounts receivable, net ($0 and $289 gross accounts receivable pledged as collateral as of September 30, 2013 and December 31, 2012, respectively)		
Customer	250	364
Other	116	161
Inventories, net		
Fossil fuel	58	65
Materials and supplies	21	19
Deferred income taxes	48	40
Receivable from Exelon intercompany money pool	1	
Prepaid utility taxes	38	21
Regulatory assets	22	32
Other	46	30
Total current assets	1,210	1,094
Property, plant and equipment, net	6,270	6,078
Deferred debits and other assets		
Regulatory assets	1,419	1,378
Investments	22	22
Investments in affiliates	8	8
Receivable from affiliates	410	360
Prepaid pension asset	368	373
Other	38	40
Total deferred debits and other assets	2,265	2,181
Total assets	$ 9,745	$ 9,353

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term notes payable accounts receivable agreement	$	$ 210
Long-term debt due within one year	300	300
Accounts payable	249	244
Accrued expenses	91	82
Payables to affiliates	51	76
Customer deposits	49	51
Regulatory liabilities	111	169
Other	28	26
Total current liabilities	879	1,158
Long-term debt	2,196	1,647
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,440	2,331
Asset retirement obligations	29	29
Non-pension postretirement benefits obligations	301	284
Regulatory liabilities	592	538
Other	105	113
Total deferred credits and other liabilities	3,467	3,295
Total liabilities	6,726	6,284
Commitments and contingencies		
Preferred securities		87
Shareholder's equity		
Common stock	2,388	2,388
Retained earnings	630	593
Accumulated other comprehensive income, net	1	1
Total shareholder's equity	3,019	2,982
Total liabilities and shareholders' equity	$ 9,745	$ 9,353

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	Total Shareholders Equity
Balance, December 31, 2012	$ 2,388	$ 593	$ 1	$ 2,982
Net income		292		292
Common stock dividends		(248)		(248)
Preferred security dividends		(1)		(1)
Redemption of preferred securities		(6)		(6)
Balance, September 30, 2013	$ 2,388	$ 630	$ 1	$ 3,019

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	**Three Months Ended September 30, 2013**	**2012**	**Nine Months Ended September 30, 2013**	**2012**
Operating revenues				
Operating revenues	$ 735	$ 716	$ 2,261	$ 2,023
Operating revenues from affiliates	2	4	10	9
Total operating revenues	737	720	2,271	2,032
Operating expenses				
Purchased power and fuel	202	253	703	747
Purchased power from affiliate	144	120	356	296
Operating and maintenance	125	172	391	460
Operating and maintenance from affiliates	21	29	59	97
Depreciation and amortization	78	68	252	218
Taxes other than income	53	48	162	143
Total operating expenses	623	690	1,923	1,961
Operating income	114	30	348	71
Other income and (deductions)				
Interest expense	(29)	(35)	(94)	(110)
Other, net	4	5	13	18
Total other income and (deductions)	(25)	(30)	(81)	(92)
Income (loss) before income taxes	89		267	(21)
Income taxes	36		107	(7)
Net income (loss)	53		160	(14)
Preference stock dividends	3	4	10	10
Net income (loss) attributable to common shareholder	50	(4)	150	(24)
Comprehensive income (loss)	$ 53	$	$ 160	$ (14)

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	**Nine Months Ended September 30, 2013**	**2012**
Cash flows from operating activities		
Net (loss) income	$ 160	$ (14)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	252	218
Deferred income taxes and amortization of investment tax credits	105	101
Other non-cash operating activities	105	148
Changes in assets and liabilities:		
Accounts receivable	(28)	
Receivables from and payables to affiliates, net	(12)	2
Inventories	(15)	21
Accounts payable, accrued expenses and other current liabilities	(5)	4
Income taxes	6	(50)
Pension and non-pension postretirement benefit contributions	(16)	(13)
Other assets and liabilities	(119)	(77)
Net cash flows provided by operating activities	433	340
Cash flows from investing activities		
Capital expenditures	(391)	(419)
Change in restricted cash	(20)	(19)
Other investing activities	2	8
Net cash flows used in investing activities	(409)	(430)
Cash flows from financing activities		
Changes in short-term debt	40	
Issuance of long-term debt	300	250
Repayment of long-term debt	(433)	(141)
Dividends paid on preference stock	(10)	(10)
Contributions from parent		66
Other financing activities	(3)	(3)
Net cash flows (used in) provided by financing activities	(106)	162
Increase (decrease) in cash and cash equivalents	(82)	72
Cash and cash equivalents at beginning of period	89	49
Cash and cash equivalents at end of period	$ 7	$ 121

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 7	$ 89
Restricted cash and cash equivalents of variable interest entity	50	30
Accounts receivable, net		
Customer	404	409
Other	132	111
Income taxes receivable		3
Inventories, net		
Gas held in storage	61	51
Materials and supplies	36	31
Deferred income taxes	5	1
Prepaid utility taxes	76	57
Regulatory assets	184	190
Other	7	8
Total current assets	962	980
Property, plant and equipment, net	5,713	5,498
Deferred debits and other assets		
Regulatory assets	509	522
Investments	5	5
Investments in affiliates	8	8
Prepaid pension asset	434	467
Other	26	26
Total deferred debits and other assets	982	1,028
Total assets	$ 7,657	$ 7,506

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 40	$
Long-term debt due within one year		400
Long-term debt of variable interest entity due within one year	69	67
Accounts payable	184	195
Accrued expenses	127	106
Deferred income taxes	9	
Payables to affiliates	54	65
Customer deposits	72	71
Regulatory liabilities	31	29
Other	58	47
Total current liabilities	644	980
Long-term debt	1,746	1,446
Long-term debt to financing trust	258	258
Long-term debt of variable interest entity	230	265
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,759	1,658
Asset retirement obligations	7	8
Non-pension postretirement benefits obligations	221	229
Regulatory liabilities	218	214
Other	66	90
Total deferred credits and other liabilities	2,271	2,199
Total liabilities	5,149	5,148
Commitments and contingencies		
Shareholders equity		
Common stock	1,360	1,360
Retained earnings	958	808
Total shareholder's equity	2,318	2,168
Preference stock not subject to mandatory redemption	190	190
Total equity	2,508	2,358
Total liabilities and shareholders equity	$ 7,657	$ 7,506

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholders Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2012	$ 1,360	$ 808	$ 2,168	$ 190	$ 2,358
Net income		160	160		160
Preference stock dividends		(10)	(10)		(10)
Balance, September 30, 2013	$ 1,360	$ 958	$ 2,318	$ 190	$ 2,508

See the Combined Notes to Consolidated Financial Statements

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution businesses. Prior to March 12, 2012, Exelon s principal, wholly owned subsidiaries included ComEd, PECO and Generation. On March 12, 2012, Constellation merged into Exelon with Exelon continuing as the surviving corporation pursuant to the transactions contemplated by the Agreement and Plan of Merger (the Merger Agreement). As a result of the merger transaction, Generation now includes the former Constellation generation and customer supply operations. BGE, formerly Constellation s regulated utility subsidiary, is now a subsidiary of Exelon. Refer to Note 4 Merger and Acquisitions for further information regarding the merger 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.

For financial statement purposes, beginning on March 12, 2012, disclosures that solely relate to Constellation or BGE activities now also apply to Exelon, unless otherwise noted. When appropriate, Exelon, Generation, ComEd, PECO and BGE are named specifically for their related activities and disclosures.

Exelon did not apply push-down accounting to BGE. As a result, BGE continues to maintain its reporting requirements as an SEC registrant. The information disclosed for BGE represents the activity of the standalone entity for the three and nine months ended September 30, 2013 and 2012 and the financial position as of September 30, 2013 and December 31, 2012. However, for Exelon s financial reporting, Exelon is reporting BGE activity for the three and nine months ended September 30, 2013 and from March 12, 2012 through September 30, 2012 and the financial position as of September 30, 2013 and December 31, 2012.

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

For the nine months ended September 30, 2013, BGE recorded a $2 million correcting adjustment to decrease amortization expense related to regulatory assets that were originally recorded during 2012 and a $4 million correcting adjustment to decrease operating and maintenance expense for an overstatement of BGE s life insurance obligation related to post-employment benefits in prior years. Exelon and BGE have concluded that these correcting adjustments are not material to their respective results of operations or cash flows for the nine months ended September 30, 2013 or any prior period presented. Exelon and BGE do not expect these correcting adjustments to have a material impact on their respective results of operations or cash flows for the year ended December 31, 2013.

The accompanying consolidated financial statements as of September 30, 2013 and 2012 and for the three and nine months then ended are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2012 Consolidated Balance Sheets were obtained from audited financial statements. Certain prior year amounts in Exelon s and BGE s Consolidated Statements of Cash Flows, Exelon s, Generation's and BGE s Consolidated Statements of Operations and Comprehensive Income and in Exelon s, Generation's, ComEd s, and BGE s Consolidated Balance Sheets have been reclassified between line items for comparative purposes. BGE recorded an adjustment to its Consolidated Statement of Cash Flows for the nine months ended September 30, 2012 to reflect the change in operating cash flows and capital expenditures related to amounts not paid of approximately $17 million. The reclassifications did not materially affect any of the Registrants net income or cash flows from operating or investing activities. Financial results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for fiscal year ended December 31, 2013. 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 2012 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 2013.

Presentation of Items Reclassified out of Accumulated Other Comprehensive Income

In February 2013, the FASB issued authoritative guidance requiring entities to present either in the notes or parenthetically on the face of the financial statements, reclassifications from each component of accumulated other comprehensive income and the affected income statement line items. Entities only need to disclose the affected income statement line item for components reclassified to net income in their entirety; otherwise, a cross-reference to the related note should be provided. This guidance was effective for the Registrants for periods beginning after December 15, 2012 and was required to be applied prospectively. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the Registrants results of operations, cash flows or financial positions. See Note 16 Changes in Accumulated Other Comprehensive Income for the new disclosures.

Disclosures About Offsetting Assets and Liabilities

In December 2011, the FASB issued (and amended in January 2013), authoritative guidance requiring entities to disclose both gross and net information about recognized derivative instruments, including bifurcated embedded derivatives, repurchase and reverse repurchase agreements, and securities borrowing or lending transactions that are offset on the balance sheet or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the balance sheet. This guidance was effective for the Registrants for periods beginning on or after January 1, 2013 and is required to be applied retrospectively. This guidance is primarily applicable to certain derivative transactions for Exelon and Generation. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the Registrants results of operations, cash flows or financial positions. See Note 10 Derivative Financial Instruments for the new disclosures.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Inclusion of the Fed Funds Effective Swap Rate as a Benchmark Interest Rate for Hedge Accounting Purposes

In July 2013, the FASB issued authoritative guidance permitting entities to designate the Fed Funds Effective Swap Rate as a U.S. benchmark interest rate for hedge accounting purposes. Prior to the issuance of this guidance, only interest rates on direct treasury obligations of the U.S. government and the LIBOR swap rate were considered benchmark interest rates in the U.S. This guidance was effective immediately and can be applied prospectively for qualifying new or redesignated hedging relationships entered into on or after July 17, 2013. Currently, the Registrants do not use the Fed Funds Effective Swap Rate as a benchmark interest rate, but may in the future.

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

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. Currently, the Registrants present their unrecognized tax benefits as liabilities on a gross basis unless an unrecognized tax benefit is directly associated with a tax position taken in a tax year that results in the recognition of a net operating loss or other tax carryforward for that year. This guidance is effective for the Registrants for periods beginning after December 15, 2013 and is required to be applied prospectively, with retroactive application permitted. The Registrants are currently assessing the impacts this guidance may have on their financial positions and cash flows. The adoption of this standard will not impact the Registrants results of operations.

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 impact the entity s economic performance.

As of September 30, 2013 and December 31, 2012, the Registrants consolidated four and five VIEs or VIE groups, respectively, for which the Registrants were the primary beneficiary and the Registrants had significant interests in seven and nine other VIEs for which the Registrants do not have the power to direct the entities activities, respectively, and, accordingly, were not the primary beneficiary.

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 to enter into a collateralized gas supply agreement with a third-party gas supplier;

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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. In the case of BondCo, BGE is required to remit all payments it receives from all residential customers through non-bypassable, rate stabilization charges to BondCo. During the three and nine months ended September 30, 2013, BGE remitted $24 million and $63 million, respectively, to BondCo. During the three and nine months ended September 30, 2012, BGE remitted $27 million and $62 million, respectively, to BondCo.

Except for providing capital funding to the solar entities for ongoing construction of the solar power facilities and a $75 million parental guarantee to the third-party gas supplier in support of the retail gas group, during the nine months ended September 30, 2013 and year ended December 31, 2012:

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

Exelon, Generation and BGE did not have any contractual commitments or obligations to provide financial support to the VIEs; and

the creditors of the VIEs did not have recourse to Exelon s, Generation s or BGE s general credit.

The carrying amounts and classification of the consolidated VIEs assets and liabilities included in Exelon s, Generation s, and BGE s consolidated financial statements at September 30, 2013 and December 31, 2012 are as follows:

	September 30, 2013			December 31, 2012		
	Exelon(a)(b)	Generation(b)	BGE	Exelon(a)(b)(c)	Generation(b)(c)	BGE
Current assets	$ 391	$ 330	$ 50	$ 550	$ 519	$ 30
Noncurrent assets	1,900	1,877	3	1,802	1,762	
Total assets	$ 2,291	$ 2,207	$ 53	$ 2,352	$ 2,281	$ 30
Current liabilities	$ 453	$ 366	$ 77	$ 685	$ 613	$ 71
Noncurrent liabilities	859	608	230	837	532	265
Total liabilities	$ 1,312	$ 974	$ 307	$ 1,522	$ 1,145	$ 336

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Includes total liabilities of $53 million as of September 30, 2013 and total assets of $116 million and total liabilities of $62 million as of December 31, 2012 related to deferred and accrued taxes that have been recorded and are not restricted for use by three of the consolidated VIEs.
(c) Includes total assets of $146 million and total liabilities of $42 million as of December 31, 2012 related to a retail power supply company that is no longer a consolidated VIE as of September 30, 2013.

In August 2013, Generation executed an agreement to terminate its energy supply contract with a retail power supply company that was previously a consolidated VIE. Generation did not have an ownership interest in the entity, but was the primary beneficiary through the energy supply contract. As a result of the termination, Generation no longer has a variable interest in the retail power supply company and ceased consolidation of the entity during the third quarter of 2013. Upon deconsolidation, there was no gain or loss recognized. The assets, liabilities, and non-controlling interest were removed from Generation s balance sheet and the change in non-controlling interest is also reflected on the Statement of Changes in Shareholders Equity.

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

Unconsolidated Variable Interest Entities

Exelon s and Generation s variable interests in unconsolidated VIEs generally include three transaction types: (1) equity method investments, (2) energy purchase and sale contracts, and (3) fuel purchase commitments. For the equity method investments, the carrying amount of the investments is reflected on their Consolidated Balance Sheets in Investments in affiliates. 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.

Fuel purchase commitments where Generation has a variable interest, but the variable interest is not significant and Generation is not the primary beneficiary, thus consolidation is not required.

ComEd s, PECO s and BGE s retail operations frequently include the purchase of electricity and RECs through procurement contracts of varying durations. None of ComEd, PECO or BGE considers itself the primary beneficiary of any VIEs as a result of these commercial arrangements.

Investment in energy development projects for which Generation has concluded that consolidation is not required.

As of September 30, 2013 and December 31, 2012, Exelon and Generation had significant unconsolidated variable interests in seven and nine, respectively, VIEs for which they were not the primary beneficiary; including certain equity method investments and certain commercial agreements. The change in the number of unconsolidated variable interests is driven by the completion of certain obligations which cause the entities to no longer be unconsolidated variable interests. The following tables present summary information about the significant unconsolidated VIE entities:

September 30, 2013	Commercial Agreement VIEs	Equity Method Investment VIEs	Total
Total assets(a)	$ 115	$ 366	$ 481
Total liabilities(a)	3	126	129

Registrants ownership interest(a)		97	97
Other ownership interests(a)	112	143	255
Registrants maximum exposure to loss:			
Carrying amount of equity method investments		78	78
Contract intangible asset	9		9
Debt and payment guarantees		5	5
Net assets pledged for Zion Station decommissioning(b)	43		43

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

December 31, 2012	Commercial Agreement VIEs	Equity Method Investment VIEs	Total
Total assets(a)	$ 386	$ 354	$ 740
Total liabilities(a)	219	114	333
Registrants ownership interest(a)		97	97
Other ownership interests(a)	167	143	310
Registrants maximum exposure to loss:			
Letters of credit	5		5
Carrying amount of equity method investments		77	77
Contract intangible asset	8		8
Debt and payment guarantees		5	5
Net assets pledged for Zion Station decommissioning(b)	50		50

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

(b) These items represent amounts on Exelon s and Generation s Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $486 million and $614 million as of September 30, 2013 and December 31, 2012, respectively; offset by payables to ZionSolutions LLC of $443 million and $564 million as of September 30, 2013 and December 31, 2012, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

For each unconsolidated VIE, 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 agreements with, or commitments by, third parties that would affect the fair value or risk of their variable interests in these variable interest entities.

4. Merger and Acquisitions

Merger with Constellation (Exelon, Generation, ComEd, PECO and BGE)

Description of Transaction

On March 12, 2012, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation s interest in RF HoldCo LLC, which holds Constellation s interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon s interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including those with generation and customer supply operations that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger.

Regulatory Matters

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The direct investment estimate includes $95 million to $120 million relating to the construction of a headquarters building in Baltimore for Generation s competitive energy businesses. On March 20, 2013, Generation signed a 20 year lease agreement that is contingent upon the developer obtaining all required approvals, permits and financing for the construction of the building. Once required approvals are received and financing conditions are met, construction will commence and the building is expected to be ready for occupancy in approximately 2 years after building construction commences. The direct investment estimate also includes $625 million for Exelon s and Generation s commitment to develop or assist in development of 285 300 MWs of new generation in Maryland, expected to be completed over a period of 10 years. Such costs, which are expected to be primarily capital in nature, will be recognized as incurred. As of September 30, 2013, amounts reflected in the Exelon and Generation consolidated financial statements for these expenditure commitments were immaterial. On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland site with 120MW of new natural gas-fired generation to satisfy certain of these commitments and achievement of commercial operation is expected in 2015. See Note 18 Commitments and Contingencies for additional information.

The MDPSC Order contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed, making liquidated damages payments. Exelon and Generation expect that the majority of these commitments will be satisfied by building or acquiring generating assets and, therefore, will be primarily capital in nature and recognized as incurred. If in the future Exelon determines that it is probable that it will make subsidy, compliance or liquidated damages payments related to the new generation development commitments, Exelon will record a liability at that time. As of September 30, 2013, it is reasonably possible that Exelon will be required to make subsidy or liquidated damages payments of approximately $40 million rather than build one of the generation projects contemplated by the commitments, given that the generation build is dependent upon the passage of legislation and other conditions that Exelon does not control.

Associated with certain of the regulatory approvals required for the merger, on November 30, 2012, a subsidiary of Generation sold three Maryland generating stations and associated assets, Brandon Shores and H.A. Wagner in Anne Arundel County, Maryland, and C.P. Crane in Baltimore County, Maryland, to Raven Power Holdings LLC (Raven Power), a subsidiary of Riverstone Holdings LLC. In 2012, Exelon and Generation recorded a pre-tax loss of $272 million to reflect the difference between the sales price and the carrying value of the generating stations and associated assets. In the first quarter of 2013, Exelon and Generation recorded a pre-tax gain of $8 million to reflect the final settlement of the sales price with Raven Power.

Accounting for the Merger Transaction

The fair value of Constellation s non-regulated business assets acquired and liabilities assumed 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 financial statements of BGE do not include fair value adjustments for assets or liabilities subject to rate-setting provisions for BGE. BGE is subject to the rate-setting authority of FERC and the MDPSC and is accounted for pursuant to the accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for BGE provide revenue derived from costs including a return on investment of assets and liabilities included in rate base. Except for debt, fuel supply contracts and regulatory assets not earning a return, the fair values of BGE's tangible and intangible assets and liabilities subject to these rate-setting

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

provisions are assumed to approximate their carrying values and, therefore, do not reflect any net adjustments related to these amounts. For BGE s debt, fuel supply contracts and regulatory assets not earning a return, the difference between fair value and book value of BGE s assets acquired and liabilities assumed is recorded as a regulatory asset and liability at Exelon Corporate as Exelon did not apply push-down accounting to BGE. See Note 1 Basis of Presentation for additional information on BGE s push-down accounting treatment. Also see Note 5 Regulatory Matters for additional information on BGE s regulatory assets.

The preliminary valuations performed in the first quarter of 2012 were updated in the second, third and fourth quarters of 2012, with the most significant adjustments to the preliminary valuation amounts having been made to the fair values assigned to the acquired power supply and fuel contracts, unregulated property, plant and equipment and investments in affiliates. There were no significant adjustments to the purchase price allocation in the first quarter of 2013 and the purchase price allocation was final as of March 31, 2013.

The final purchase price allocation of the Merger of Exelon with Constellation and Exelon s contribution of certain subsidiaries of Constellation to Generation was as follows:

Purchase Price Allocation, excluding amortization	Exelon	Generation
Current assets	$ 4,936	$ 3,638
Property, plant and equipment	9,342	4,054
Unamortized energy contracts	3,218	3,218
Other intangibles, trade name and retail relationships	457	457
Investment in affiliates	1,942	1,942
Pension and OPEB regulatory asset	740	
Other assets	2,265	1,266
Total assets	22,900	14,575
Current liabilities	3,408	2,804
Unamortized energy contracts	1,722	1,512
Long-term debt, including current maturities	5,632	2,972
Noncontrolling interest	90	90
Deferred credits and other liabilities and preferred securities	4,683	1,933
Total liabilities, preferred securities and noncontrolling interest	15,535	9,311
Total purchase price	$ 7,365	$ 5,264

Intangible Assets Recorded

For the power supply and fuel contracts acquired from Constellation, the difference between the contract price and the market price at the date of the merger was recognized as either an intangible asset or liability based on whether the contracts were in or out-of-the-money. The fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the merger date. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues. Exelon and Generation present separately in their Consolidated Balance Sheets the unamortized energy contract assets and liabilities for these contracts. Exelon s and Generation s amortization expense for the three and nine months ended September 30, 2013 amounted to $40 million and $372 million, respectively. Exelon s and Generation s amortization expense for the three months ended September 30, 2012 and for the period March 12, 2012 to September 30, 2012 amounted to $261 million and $794 million, respectively. In addition, Exelon Corporate has established a regulatory asset and an unamortized energy contract liability related to BGE s power supply and fuel contracts. The power supply and fuel contracts regulatory asset amortization was $19 million and $57 million for the three and nine months ended September 30, 2013, respectively, and $36 million and $80 million

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

for the three months ended September 30, 2012 and for the period March 12, 2012 to September 30, 2012, respectively. An equally offsetting amortization of the unamortized energy contract liability has been recorded at Exelon Corporate in the Consolidated Statement of Operations.

Exelon s and Generation s amortization expense for the fair value of the Constellation trade name intangible asset for the three and nine months ended September 30, 2013 amounted to $8 million and $20 million, respectively. Exelon s and Generation s straight line amortization expense for the fair value of the Constellation trade name intangible asset for the three months ended September 30, 2012 and the period March 12, 2012 to September 30, 2012 amounted to $6 million and $14 million, respectively. The trade name intangible asset is included in deferred debits and other assets within Exelon s and Generation s Consolidated Balance Sheets.

The intangible assets for the fair value of the retail relationships are amortized as amortization expense on a straight line basis over the useful life of the underlying assets. Exelon s and Generation s straight line amortization expense for the three and nine months ended September 30, 2013 amounted to $8 million and $17 million, respectively. Exelon s and Generation s straight line amortization expense for the three months ended September 30, 2012 and the period March 12, 2012 to September 30, 2012 amounted to $2 million and $9 million, respectively. The retail relationships intangible assets are included in deferred debits and other assets within Exelon s and Generation s Consolidated Balance Sheets.

Exelon s intangible assets and liabilities acquired through the merger with Constellation included in its Consolidated Balance Sheets, along with the future estimated amortization, were as follows as of September 30, 2013:

					Estimated amortization expense					
Description	**Weighted Average Amortization (Years)(b)**	**Gross**	**Accumulated Amortization**	**Net**	**Remainder of 2013**	**2014**	**2015**	**2016**	**2017**	**2018 and Beyond**
Unamortized energy contracts, net(a)	1.5	$ 1,499	$ (1,299)	$ 200	$ 79	$ 75	$ 18	$ (31)	$ (21)	$ 80
Trade name	10.0	243	(40)	203	6	24	24	24	24	101
Retail relationships	12.4	214	(31)	183	5	19	18	18	18	105
Total, net		$ 1,956	$ (1,370)	$ 586	$ 90	$ 118	$ 60	$ 11	$ 21	$ 286

(a) Includes the fair value of BGE's power and gas supply contracts of $32 million for which an offsetting regulatory asset was also recorded.
(b) Weighted average amortization period was calculated as of the date of acquisition.

Impact of Merger

It is impracticable to determine the overall financial statement impact for the Constellation subsidiaries contributed down to Generation following the Upstream Merger for the three and nine months ended September 30, 2012. Upon closing of the merger, the operations of these Constellation subsidiaries were integrated into Generation s operations and are therefore not fully distinguishable after the merger.

The impact of BGE on Exelon s Consolidated Statement of Operations and Comprehensive Income included operating revenues of $720 million and no net income during the three months ended September 30, 2012, and operating revenues of $1,388 million and net loss of $49 million during the nine months ended September 30, 2012.

During the three months ended September 30, 2013, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $43 million, $32 million, $5 million, $3 million and $2 million, respectively. During the nine months ended September 30, 2013, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $106 million, $75 million, $14 million, $8 million and $5 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $15 million, $10 million and $5 million, respectively, as a regulatory asset as of September 30, 2013. Additionally, Exelon and BGE established a regulatory asset of $6 million as of September 30, 2013 for previously incurred 2012 merger and integration-related costs.

During the three months ended September 30, 2012, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $95 million, $79 million, $8 million, $3 million and $1 million, respectively. During the nine months ended September 30, 2012, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $729 million, $283 million, $34 million, $13 million and $172 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $49 million, $30 million and $19 million, respectively, as a regulatory asset as of September 30, 2012.

The costs incurred are classified primarily within Operating and Maintenance Expense in the Registrants respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the BGE customer rate credit and the credit facility fees, which are included as a reduction to operating revenues and other, net, respectively, for the three and nine months ended September 30, 2012. See Note 18 Commitments and Contingencies for additional information.

Severance Costs

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

Upon closing the merger with Constellation, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. The majority of these positions are corporate and Generation support positions. Since then, Exelon has identified specific employees to be severed pursuant to the merger-related staffing and selection process as well as employees that were previously identified for severance but have since accepted another position within Exelon and are no longer receiving a severance benefit. Exelon adjusts its accrual each quarter to reflect its best estimate of remaining severance costs. In addition, certain employees identified during the staffing and selection process also receive pension and other postretirement benefits that are deemed contractual termination benefits, which the Registrants recorded during the second quarter of 2012.

The amount of severance expense associated with the post-merger integration recognized for the three months ended September 30, 2013 for Exelon and Generation were $3 million and $3 million, respectively. For Generation, $2 million represents amounts billed by BSC through intercompany allocations. The amount of severance expense associated with the post-merger integration recognized for the nine months ended September 30, 2013 for Exelon and Generation were $6 million and $6 million, respectively. For Generation, $5 million represents amounts billed by BSC through intercompany allocations. There was no severance expense associated with post-merger integration recognized for the three and nine months ended September 30, 2013 for ComEd, PECO and BGE. Estimated costs to be incurred after September 30, 2013 are not material.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

For the three and nine months ended September 30, 2012, the Registrants recorded the following severance benefits costs associated with the identified job reductions within operating and maintenance expense in their Consolidated Statements of Operations, except for ComEd and BGE:

Three Months Ended September 30, 2012 **Severance Benefits(a)**	**Exelon**	**Generation**	**ComEd(b)**	**PECO**	**BGE(c)**
Severance charges	$ 8	$ 4	$ 1	$ 1	$ 1
Stock compensation	3	2	1		
Total severance benefits	$ 11	$ 6	$ 2	$ 1	$ 1

Nine Months Ended September 30, 2012 **Severance Benefits(a)**	**Exelon**	**Generation**	**ComEd(b)**	**PECO**	**BGE(c)**
Severance charges	$ 117	$ 68	$ 16	$ 8	$ 18
Stock compensation	6	4	1		
Other charges(d)	7	4	1		1
Total severance benefits	$ 130	$ 76	$ 18	$ 8	$ 19

(a) The amounts above include $0 million and $40 million at Generation, $2 million and $16 million at ComEd, $1 million and $8 million at PECO, and $1 million and $7 million at BGE, for amounts billed by BSC through intercompany allocations for the three and nine months ended September 30, 2012, respectively.
(b) ComEd established regulatory assets of $2 million and $18 million for severance benefits costs for the three and nine months ended September 30, 2012, respectively. The majority of these costs are expected to be recovered over a five-year period.
(c) BGE established regulatory assets of $1 million and $19 million for severance benefits costs for the three and nine months ended September 30, 2012, respectively. The majority of these costs are being recovered over a five-year period beginning in March 2013.
(d) Primarily includes life insurance, employer payroll taxes, educational assistance and outplacement services.

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

Nine Months Ended September 30, 2013 **Severance liability**	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
Balance at December 31, 2012	$ 111	$ 33	$ 1	$	$ 11
Severance charges(a)	5	1			
Stock compensation	1				
Payments	(52)	(20)			(4)
Balance at September 30, 2013	$ 65	$ 14	$ 1	$	$ 7

(a) Includes salary continuance and health and welfare severance benefits. Amounts represent ongoing severance plan benefits.

Cash payments under the plan began in the second quarter of 2012. Substantially all cash payments under the plan are expected to be made by the end of 2016.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The Registrants provide severance and health and welfare benefits under Exelon s ongoing severance benefit plans to terminated employees in the normal course of business, which are not directly related to the merger with Constellation. These benefits are accrued for when the benefits are considered probable and can be reasonably estimated.

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

Severance Benefits(a)	Exelon	Generation	ComEd	PECO	BGE
Severance charges three months	$ 12	$ 11	$ 1	$	$
Severance charges nine months	14	12	2		

(a) The amounts above for Generation include $1 million for amounts billed by BSC through intercompany allocations for the three and nine months ended September 30, 2013.

For the three and nine months ended September 30, 2012, the Registrants recorded the following severance costs associated with these ongoing severance benefits within operating and maintenance expense in their Consolidated Statements of Operations:

Severance Benefits(a)	Exelon	Generation	ComEd	PECO	BGE
Severance charges three months	$ 5	$ 3	$ 1	$	$ 1
Severance charges nine months	11	8	1		2

(a) The amounts above for Generation include $1 million for amounts billed by BSC through intercompany allocations for the three and nine months ended September 30, 2012.

The severance liability balances associated with these ongoing severance benefits as of September 30, 2013 and December 31, 2012 are not material.

Pro-forma Impact of the Merger

The following unaudited pro forma financial information reflects the consolidated results of operations of Exelon and Generation as if the merger with Constellation had taken place on January 1, 2011. The unaudited pro forma information was calculated after applying Exelon s and Generation s accounting policies and adjusting Constellation s results to reflect purchase accounting adjustments.

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

	Three Months Ended September 30, 2012	
	Generation	Exelon
Total Revenues	$ 4,293	$ 6,841
Net income attributable to Exelon	282	492
Basic Earnings Per Share	n.a.	$ 0.58
Diluted Earnings Per Share	n.a.	0.57

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Nine Months Ended September 30, 2012	
	Generation	**Exelon**
Total Revenues	$ 12,753	$ 20,084
Net income attributable to Exelon	805	1,439
Basic Earnings Per Share	n.a.	$ 1.79
Diluted Earnings Per Share	n.a.	1.79

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 2012 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. 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 to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This 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. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd s best estimate of the revenue requirement expected to be approved by the ICC for that year s reconciliation. As of September 30, 2013, and December 31, 2012, ComEd had recorded a net regulatory asset associated with the distribution formula rate of $404 million and $209 million, respectively.

During March 2013, the Illinois House and Senate each passed Senate Bill 9 with supermajority votes to clarify the intent of EIMA on three major issues: the use of year-end rather than average rate base and capital structure in the annual reconciliation, the use of ComEd s weighted average cost of capital interest rate to apply to the annual reconciliation and an allowed return on ComEd s pension asset. On May 22, 2013, the Illinois General Assembly overrode the Governor s May 5, 2013 veto of Senate Bill 9, which resulted in the legislation becoming effective immediately. ComEd projects the override of Senate Bill 9 will result in increased operating revenues of approximately $25 million for 2013 and $65 million in 2014. Also, ComEd projects that Senate Bill 9 will accelerate capital expenditures by approximately $40 million and $45 million in 2013 and 2014, respectively.

On May 30, 2013, ComEd updated the distribution formula rate structure to reflect the impacts of Senate Bill 9. On June 5, 2013, the ICC approved the May 30 filing implementing ComEd s formula rate structure change as well as the resulting reduction to the current revenue requirement in effect of $14 million, which was reflected in customer rates effective July 1, 2013.

On May 31, 2013, ComEd updated its April 29, 2013, distribution formula rate filing to reflect the impacts of Senate Bill 9. The May 31, 2013 filing establishes the revenue requirement used to set the rates that will take effect in January 2014 after the ICC s review and approval, which is due by December 25, 2013. The revenue requirement requested is based on 2012 actual costs and projected 2013 capital additions as well as an annual

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

reconciliation of the revenue requirement in effect in 2012 to the actual costs incurred for that year. ComEd s current request is a total increase to the revenue requirement including the impacts of Senate Bill 9, of $353 million, reflecting an increase of $162 million for the initial revenue requirement for 2013 and an increase of $191 million for the annual reconciliation for 2012. The revenue requirement provides for a weighted average debt and equity return on distribution rate base of 6.94% inclusive of an allowed return on common equity of 8.72%, reflecting the average rate on 30-year treasury notes plus 580 basis points.

On September 4, 2013, the Attorney General filed a complaint (the Complaint) with the ICC to change the formula rate structure approved by the ICC on June 5, 2013. In the Complaint, the Attorney General proposed the following three changes to the formula: the elimination of the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance, the netting of associated accumulated deferred income taxes against the annual reconciliation balance in calculating interest, and the use of average rather than year-end rate base for determining any ROE collar adjustment. On October 2, 2013, the ICC opened an investigation (the Investigation) in which it undertook to review the three issues raised in the Complaint and determine if ComEd s current formula rate structure complies with Senate Bill 9. On October 31, 2013, the Attorney General asked to voluntarily withdraw the Complaint. ComEd is unable to predict the outcome of the ICC s Investigation; however, if the ICC were to rule against ComEd on these three issues, the impact could be material to ComEd s results of operations, cash flows, and financial position. ComEd expects the Investigation to be resolved in the fourth quarter of 2013.

On April 1, 2013, ComEd filed annual progress reports on both its AMI Implementation Plan and Infrastructure Investment Plan as required by EIMA. On April 9, 2013, the ICC initiated an investigation to review ComEd s progress on its AMI Implementation Plan. The ICC did not initiate an investigation on ComEd s Infrastructure Investment Plan. On June 5, 2013, the ICC issued an interim order approving ComEd s accelerated AMI deployment plan consistent with the provisions of Senate Bill 9. In September 2013, ComEd began smart grid deployment with 60,000 meters to be installed by the end of 2013. On June 26, 2013, the ICC issued a final order on the overall progress of ComEd s AMI Implementation Plan with no significant findings.

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

The Court held the ICC abused its discretion in not reducing ComEd s rate base to account for an additional 18 months of accumulated depreciation while including post-test year pro forma plant additions through that period (the same position ComEd took in its 2010 electric distribution rate case (2010 Rate Case) discussed below). ComEd continued to bill rates as established under the ICC s order in the 2007 Rate Case until June 1, 2011, when the rates set in the 2010 Rate Case became effective. In August 2011, ComEd filed testimony in the remand proceeding that no refunds should be required. The ICC subsequently initiated a proceeding on remand. On February 23, 2012, the ICC issued an order on remand in the proceeding requiring ComEd to provide a refund of approximately $37 million to customers related to the treatment of post-test year accumulated depreciation issue. On March 26, 2012, ComEd filed a notice of appeal with the Court.

On October 1, 2013, the Court ruled against ComEd on the accumulated depreciation issue. The Court affirmed that ComEd owes a refund to customers of $37 million. As of September 30, 2013, and December 31, 2012, ComEd was fully reserved for this liability. ComEd will not seek rehearing or appeal on this matter and is working with the ICC on the process and timing for a refund to customers.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

2010 Illinois Electric Distribution Rate Case (Exelon and ComEd). On June 30, 2010, ComEd filed its 2010 Rate Case requesting ICC approval for an increase of $396 million to its annual delivery services revenue requirement. This request was subsequently reduced to $343 million to account for changes in tax law, corrections, acceptance of limited adjustments proposed by certain parties and the amounts expected to be recovered in the AMI pilot program tariff. The request to increase the annual revenue requirement was to allow ComEd to recover the costs of substantial investments made since its last rate filing in 2007. The requested increase also reflected increased costs, most notably pension and OPEB, since ComEd s rates were last determined. The original requested rate of return on common equity was 11.5%. In addition, ComEd requested future recovery of certain amounts that were previously recorded as expense that would allow ComEd to recognize a one-time benefit of up to $40 million (pre-tax). The requested increase also included $22 million for increased uncollectible accounts expense, which would increase the threshold for determining over/under recoveries under ComEd s uncollectible accounts tariff.

On May 24, 2011, the ICC issued an order, which became effective on June 1, 2011. The order approved a $143 million increase to ComEd s annual delivery services revenue requirement and a 10.5% rate of return on common equity. As expected, the ICC followed the Court s ruling in ComEd s 2007 Rate Case on the post-test year accumulated depreciation issue. The order allowed ComEd to establish or reestablish a net amount of approximately $40 million of previously expensed plant balances or new regulatory assets, which was reflected as a reduction in operating and maintenance expense and income tax expense in 2011. The order also affirmed the current regulatory asset for severance costs, which was challenged by an intervener in the 2010 Rate Case. The order was appealed to the Court by several parties on a number of issues. On May 16, 2013, the Court dismissed as moot the appeals of the ICC s order in the 2010 Rate Case as ComEd now recovers distribution costs under EIMA through a pre-established formula rate tariff. See Note 3 of Exelon s 2012 Form 10-K for further details on ComEd s 2007 Rate Case and 2010 Rate Case.

Illinois Procurement Proceedings (Exelon and ComEd). ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. The IPA s 2013 procurement plan, approved by the ICC, provides for curtailment of the existing long-term contracts for renewable energy and RECs in response to the increased number of ComEd s customers purchasing their energy from competitive electric generation suppliers on their own or through municipal aggregation. In March 2013, ICC staff and the IPA approved ComEd s updated load forecast. Purchases under the existing long-term contracts for energy and the associated RECs were reduced on a pro-rata basis under the terms of those contracts for the June 2013 May 2014 period to keep the purchases under the statutory rate impact cap. The curtailment s impact on ComEd s financial position and cash flows was immaterial.

On December 19, 2012, the ICC issued an order directing ComEd and Ameren (the Utilities) to enter into 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 proposed term of the sourcing agreement is 20 years. The project was approved by the DOE on February 4, 2013. The sourcing agreement was approved by the ICC on June 26, 2013 in a separate proceeding, with the ICC ordering ComEd to execute the sourcing agreement no later than 60 days after the date of the order. The sourcing agreement stipulates that the Utilities will pay FutureGen s contract prices, which are set annually based on a formula rate construct. 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. On January 22, 2013, ComEd filed an application for rehearing, requesting the ICC reconsider its December 2012 order requiring the Utilities to procure the entire output of the FutureGen facility. On January 29, 2013, the ICC denied ComEd s rehearing request. ComEd filed an appeal with the Illinois Appellate Court on February 22, 2013, questioning the legality of requiring ComEd to procure power for retail customers purchasing electricity from competitive electric generation suppliers.

On August 22, 2013, the Utilities executed the contract 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 contract should be suspended. Depending on the ultimate outcome of the appeals, 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.

See Note 18 Commitments and Contingencies for additional information on ComEd s energy commitments and ICC s proceedings related to storm waivers.

Pennsylvania Regulatory Matters

Pennsylvania Procurement Proceedings (Exelon and PECO). PECO s first PAPUC approved DSP Program, under which PECO was providing default electric service, had a 29-month-term that ended May 31, 2013. 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 will begin in December 2013. 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 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.

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 the remainder 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

cost of the original meters (as further described below), on its smart meter infrastructure and approximately $120 million on smart grid investments through 2014 of which $200 million will be funded by SGIG as discussed below. As of September 30, 2013, PECO has spent $364 million and $111 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received to date.

Pursuant to the ARRA of 2009, PECO and the DOE entered into a Financial Assistance Agreement to extend PECO $200 million in non-taxable SGIG funds of which $140 million relates to smart meter deployment and $60 million relates to smart grid infrastructure. As part of the agreement, the DOE has a conditional ownership interest in qualifying Federally-funded project property and equipment, which is subordinate to PECO s existing mortgage. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. As of September 30, 2013, PECO has received $181 million of the $200 million in reimbursements. PECO s outstanding receivable from the DOE for reimbursable costs was $6 million as of September 30, 2013, 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 $19 million, net of approximately $16 million of reimbursements from the DOE. PECO is seeking full recovery of all incurred costs related to the original deployment of meters. For amounts not recovered from the vendor, PECO will seek regulatory rate recovery in a future filing with the PAPUC. PECO did not seek recovery of original meter costs in the January 2013 universal deployment filing, as resolution with the vendor is still pending. 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. In the May 31, 2013 Joint Petition for Settlement of the universal deployment plan, the parties agreed to defer any potential challenges to cost recovery of the original meters as discussed above.

As of September 30, 2013, PECO believes the amounts incurred for the original meters and related installation and removal costs are probable of recovery based on applicable case law and past precedent on reasonably and prudently incurred costs. As a result, a regulatory asset of $17 million, representing the cost of the original meters, net of accumulated depreciation and DOE reimbursements, was recorded on Exelon s and PECO s Consolidated Balance Sheets. On August 15, 2013, PECO entered into an agreement with the vendor, which is anticipated to be part of a larger agreement, and under which PECO transferred the original uninstalled meters to the vendor and will receive approximately $12 million in return, of which $2 million has been received as of September 30, 2013. As a result, during the third quarter of 2013, the $17 million regulatory asset was reduced to $5 million. The agreement does not fully resolve the claim against the vendor for the original meter costs and PECO continues to seek full recovery from the vendor of all incurred costs related to the original deployment of meters. If PECO later determines that the remaining regulatory asset is no longer probable of recovery, PECO would be required to recognize a charge in earnings in the period in which that determination was made.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 communicated its compliance with the reduction targets in a preliminary report with the PAPUC on March 1, 2013. The final compliance report is due to the PAPUC by November 15, 2013.

On March 29, 2013, PECO filed a Petition with the PAPUC to change the recovery period of certain Direct Load Control (DLC) Program costs necessary to implement the Phase I Plan. The Petition seeks approval to allow PECO to recover $12 million in equipment, installation and information technology costs for its Residential DLC program with the amounts collected for the Phase I Plan. As the Phase I Plan was implemented at a cost less than originally budgeted, PECO proposed to recover these expenses from its Phase I Energy Efficiency Program Charge over-collection consistent with PAPUC guidance to recover all Phase I costs through Phase I funding. The PAPUC approved PECO s Petition on May 9, 2013. A regulatory liability was established for the DLC program costs that will be amortized as a credit to the income statement to offset the related depreciation expense during the same period.

The PAPUC issued its Phase II EE&C implementation order on August 2, 2012, that provides energy consumption reduction requirements for the second phase of Act 129 s EE&C programs, which went into effect on June 1, 2013. The PAPUC deferred a decision on peak demand reduction requirements until late 2013. On February 28, 2013, the PAPUC approved PECO s three-year EE&C Phase II plan that was filed on November 1, 2012, and sets forth how PECO will reduce electric consumption by at least 1,125,852 MWh in its service territory for the period June 1, 2013 through May 31, 2016.

On March 15, 2013, 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, 2013 to May 31, 2014. PECO proposed to fund the estimated $10 million cost of the one-year program by modifying incentive levels for other Phase II programs. On May 9, 2013, the PAPUC approved PECO s amended EE&C Phase II plan. The costs of DLC program will be recovered through PECO s Energy Efficiency Program Charge along with all other Phase II Plan costs.

Investigation of Pennsylvania Retail Electricity Market (Exelon and PECO). On July 28, 2011, the PAPUC issued an order outlining the next steps in its investigation into the status of competition in Pennsylvania s retail electric market. The PAPUC found that the existing default service model presents substantial impediments to the development of a vibrant retail market in Pennsylvania and directed its Office of Competitive Markets Oversight to evaluate potential intermediate and long-term structural changes to the default service model. On March 1, 2012, the PAPUC issued the final order describing more detailed recommendations to be implemented prior to the expiration of the electric distribution company s current default service plan and providing guidelines for electric distribution companies for development of their next default service plan. On October 12, 2012, the PAPUC approved PECO s second DSP Program, which includes several new programs to continue PECO's support of retail market competition in Pennsylvania in accordance with the order issued by the PAPUC on December 15, 2011. Further, the PAPUC issued a final order on February 14, 2013, outlining its proposed end-state for default service, which included default service pricing for residential and small commercial customers based on three month full requirements contracts, full requirement contracts using hourly spot market pricing for large commercial and industrial default service customers, and the inclusion of CAP customers in the customer choice programs.

Pennsylvania Act 11 of 2012 (Exelon and PECO). On February 13, 2012, Act 11 was signed into law by the Governor. Act 11 seeks to clarify the PAPUC's authority to approve alternative ratemaking mechanisms, which would allow for the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities aging electric and natural gas distribution systems in Pennsylvania. Act 11 also includes a provision that allows utilities to use a fully projected future test year under which the PAPUC may permit the inclusion of projected capital costs in rate base for assets that will be placed in service during the first year that rates are in effect. The PAPUC s implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIP) which outlines how the utility is planning to increase its investment for repairing, improving, or replacing aging infrastructure, approved by the PAPUC prior to implementing a DSIC. On May 9, 2013, the PAPUC approved PECO s LTIIP for its Gas Operations, which was filed on February 8, 2013.

Maryland Regulatory Matters

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. The MDPSC s approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. As of September 30, 2013 and December 31, 2012, BGE recorded a regulatory asset of $52 million and $31 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. The MDPSC continues to evaluate the impacts of a customer opt-out feature in BGE s Smart Grid program. In March 2013, BGE filed a description of the overall additional costs associated with allowing customers to retain their current meter, and for radio frequency (RF)-Free and RF-Minimizing options related to the installation of their smart meters as well as a proposed cost recovery mechanism. The MDPSC held a hearing in August 2013 to consider the filings made by BGE and other Maryland electric utilities. The ultimate resolution related to this feature 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. Pursuant to the ARRA of 2009, BGE is a recipient of $200 million in federal funding from the DOE for its smart grid and other related initiatives, which substantially reduces the total cost of these initiatives to BGE s ratepayers. The project to install the smart meters began in late April 2012.

As of September 30, 2013, BGE had received $176 million in reimbursements from the DOE. As of September 30, 2013, BGE s outstanding receivable from the DOE for reimbursable costs was $23 million, which has been recorded in Other accounts receivable, net on Exelon s and BGE s Consolidated Balance Sheets.

New Electric Generation (Exelon, Generation and BGE). On April 12, 2012, the MDPSC issued an order directing BGE and two other Maryland utilities to enter into a contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW natural gas-fired combined-cycle generation plant in Waldorf, Maryland, that CPV projected will be in commercial operation by June 1, 2015. The initial term of the proposed contract is 20 years. The CfD mandates that BGE and the other utilities pay (or receive) the difference between CPV s contract prices and the revenues CPV receives for capacity and energy from clearing the unit in the PJM capacity market. The MDPSC s Order requires the three Maryland utilities to enter into a CfD in amounts proportionate to their relative SOS load.

On April 16, 2013, the MDPSC issued an order that required BGE to execute a specific form of contract with CPV, and the parties executed the contract as of June 6, 2013. As of September 30, 2013, there is no impact on Exelon s and BGE s results of operations, cash flows and financial positions. Furthermore, the agreement does not become effective until the resolution of certain items, including all current litigation.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

On April 27, 2012, a civil complaint was filed in the U.S. District Court for the District of Maryland by certain unaffiliated parties that challenges the actions taken by the MDPSC on Federal law grounds. On October 24, 2013, the U.S. District Court issued a judgment order finding that the MDPSC s Order directing BGE and the two other Maryland utilities to enter into a CfD, which assures that CPV receives a guaranteed fixed price regardless of the price set by the federally regulated wholesale market, violates the Supremacy Clause of the United States Constitution.

On May 4, 2012, BGE filed a petition in the Circuit Court for Anne Arundel County, Maryland, seeking judicial review of the MDPSC order under state law. That petition was subsequently transferred to the Circuit Court for Baltimore City and consolidated with similar appeals that have been filed by other interested parties. On October 1, 2013, the Circuit Court Judge issued a Memorandum Opinion and Order finding the decisions of the MDPSC were within its statutory authority under Maryland law. This decision is separate from the judgment in the federal litigation that the MDPSC Order is unconstitutional and the CfD is unenforceable under federal law. The federal judgment, if upheld, would prevent enforcement of the CfD even if the Circuit Court decision stands.

Depending on the ultimate outcome of the pending state and federal litigation, on the eventual market conditions, and on the manner of cost recovery as of the effective date of the agreement, the CfD could have a material impact on Exelon and BGE s results of operations, cash flows and financial positions.

Exelon believes that this and other states projects may have artificially suppressed capacity prices in PJM and may continue to do so in future auctions to the detriment of Exelon s market driven position. In addition to this litigation, Exelon is working with other market participants to implement market rules that will appropriately limit the market suppressing effect of such state activities.

2012 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 27, 2012, BGE filed an application for increases to its electric and gas base rates with the MDPSC. On February 22, 2013, the MDPSC issued an order in BGE s 2012 electric and natural gas distribution rate case for increases in annual distribution service revenue of $81 million and $32 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 February 23, 2013. As part of the rate order, the MDPSC approved both recovery of and return on merger integration costs incurred during the test year, including severance. As a result, the order affirmed the treatment of $20 million of severance-related costs that BGE had recorded as a regulatory asset in 2012, consistent with prior MDPSC decisions. Additionally, BGE established a new regulatory asset of $8 million related to non-severance merger integration costs, which includes $6 million of costs incurred during 2012. Current MDPSC treatment of these merger integration regulatory assets is to provide recovery over a five year period.

MDPSC Derecho Storm Order (Exelon and BGE). Following the June 2012 Derecho storm which hit the mid-Atlantic region interrupting electrical service to a significant portion of the State of Maryland, the MDPSC issued an order on February 27, 2013 requiring BGE and other Maryland utilities to file several comprehensive reports with short-term and long-term plans to improve reliability and grid resiliency that were due at various times before August 30, 2013.

BGE s May 17, 2013 distribution rate case included a short-term plan to improve reliability as well as a proposal for a surcharge to recover incremental capital expenditures and operating costs associated with the short-term plan. On September 3, 2013, BGE filed a comprehensive long term assessment examining potential alternatives for improving the resiliency of the electric grid and a staffing analysis reviewing historical staffing levels as well as forecasting staffing levels necessary under various storm scenarios. BGE currently cannot predict the outcome of these proceedings, which may result in increased capital expenditures and operating 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 rolled into 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. The new surcharge rates are expected to take effect in the first quarter of 2014. BGE currently cannot predict the outcome of this proceeding or how much of the requested planned and related surcharge 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 are 10.50% and 10.35% for electric and gas distribution, respectively. In addition to these requested rate increases, BGE s application includes a request for recovery of incremental capital expenditures and operating costs associated with BGE s proposed short-term reliability improvement plan 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. The new electric and gas distribution base rates are expected to take effect in December 2013. BGE currently cannot predict the outcome of this proceeding or how much of the requested increases the MDPSC will approve.

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 s most recent annual formula rate update filed in April 2013 reflects 2012 actual costs plus forecasted 2013 capital additions. The update resulted in a revenue requirement of $488 million plus a $25 million adjustment related to the reconciliation of 2012 actual costs for a net revenue requirement of $513 million. This compares to the May 2012 updated revenue requirement of $450 million offset by a $5 million reduction related to the reconciliation of 2011 actual costs for a net revenue requirement of $445 million. The increase in the revenue requirement was primarily driven by increased plant investment, higher pension and post-retirement healthcare costs, and higher operating and maintenance costs. The 2013 net revenue requirement became effective June 1, 2013, and is being recovered over the period extending through May 31, 2014. The regulatory asset associated with the true-up is being amortized as the associated amounts are recovered through rates.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

ComEd s updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.70%, a decrease from the 8.91% return previously authorized. The decrease in return was primarily due to lower interest rates on ComEd s long-term debt outstanding. As part of the FERC-approved settlement of ComEd s 2007 transmission rate case, the rate of return on common equity is 11.5% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the formula transmission rate is currently capped at 55%.

BGE s most recent annual formula rate update filed in April 2013 reflects actual 2012 expenses and investments plus forecasted 2013 capital additions. The update resulted in a revenue requirement of $158 million offset by a $1 million reduction related to the reconciliation of 2012 actual costs for a net revenue requirement of $157 million. This compares to the April 2012 updated revenue requirement of $156 million increased by $2 million related to the reconciliation of 2011 actual costs for a net revenue requirement of $158 million. The decrease in the revenue requirement was primarily driven by a lower realized rate of return and reduced rate base, offset partially by higher depreciation and operating and maintenance costs. The 2013 net revenue requirement became effective June 1, 2013, and is being recovered over the period extending through May 31, 2014. The regulatory asset associated with the true-up is being amortized as the associated amounts are recovered through rates.

BGE s updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.35%, a decrease from the 8.43% return previously authorized. The decrease in return was primarily due to a debt issuance in 2012 and lower interest rates on BGE s debt outstanding. As part of the FERC-approved settlement in 2006 of BGE s 2005 transmission rate case, the base 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 Pepco Holdings, Inc. companies relating to their respective transmission formula rates. BGE s formula rate includes a 10.8% base rate of return on common equity for most investments included in its rate base. 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 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. As of September 30, 2013, BGE cannot predict the likelihood or a reasonable estimate of the amount of a change, if any, in the allowed base return on equity, or a reasonable estimate of the refund period start date. While BGE cannot predict the outcome of this matter, if FERC orders a reduction of BGE s base return on equity from 10.8% to 8.7%, the estimated annual impact would be a reduction in revenues of approximately $10 million.

PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd, PECO and BGE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. In April 2007, FERC issued an order concluding that PJM s current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. After FERC ultimately denied all requests for rehearing on all issues, several parties filed petitions in the U.S. Court of Appeals for the Seventh Circuit for review of the decision. On August 6, 2009, that court issued its decision affirming FERC s order with regard to the costs of existing facilities but reversing and remanding to FERC for further consideration its decision with regard to the costs of new facilities 500 kV and above. On March 30, 2012, FERC issued an order on remand affirming the cost allocation in its April 2007 order. On March 22, 2013, FERC issued an order denying rehearing and made it clear that the cost allocation at issue concerns only projects approved prior to February 1, 2013. A number of entities have filed appeals of the FERC orders. 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 that 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 June 30, 2006 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.

On October 11, 2012, the PJM Transmission Owners filed with FERC a cost allocation for new transmission facilities asking that the new cost allocation methodology apply to all transmission approved by the PJM Board on or after February 1, 2013. The proposed methodology is a hybrid methodology that would socialize 50% of the costs of new facilities at 500kV and above and double-circuit 345kV lines, and allocate the remaining 50% to direct beneficiaries. For all other facilities, the costs would be allocated to the direct beneficiaries. On March 22, 2013, FERC issued an order accepting the cost allocation with minor exceptions and requiring a compliance filing on those few issues within 120 days of the order. The compliance filing was made on July 22, 2013.

ComEd, PECO and BGE are committed to the construction of transmission facilities under their operating agreements with PJM to maintain system reliability. ComEd, PECO and BGE will work with PJM to continue to evaluate the scope and timing of any required construction projects. There were no significant changes in baseline project commitments for ComEd, PECO and BGE through the third quarter of 2013.

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 proceedings leading to FERC s approval of the MOPR were extensive, and there have been numerous changes to the MOPR and litigation related to it since it was originally implemented. For example, in 2011 the parties disputed numerous elements of the MOPR including: (i) the default price that should apply to bids found subject to the MOPR, (ii) the duration of the MOPR and (iii) the application of the MOPR to self-supplying capacity and state-sponsored capacity. The FERC orders approving that MOPR have been appealed to the United States Court of Appeals for the Third Circuit. A resolution of that appeal is not expected until sometime in late 2013.

In May 2012 (based on the MOPR provisions the FERC approved in 2011), PJM announced the results of its capacity auction covering the delivery year ending May 31, 2016. Several new units with state-sanctioned subsidy contracts cleared in the auction at prices below the MOPR. Potentially, these states could expand such state-sanctioned subsidy programs or other states may seek to establish similar programs. Generation believed that further revisions to that MOPR were necessary to ensure that the potential to artificially reduce capacity auction prices is appropriately limited in PJM. In early December 2012, PJM filed a new MOPR for approval at the FERC, which Exelon believed would be more effective in preventing state-sanctioned subsidy contracts from artificially reducing capacity prices. Generation was actively involved in the process through which those MOPR changes were developed and supported the changes. On May 3, 2013, the FERC issued its order. While the

FERC order accepted certain aspects of the proposal that Exelon supported (such as applying the MOPR to all of PJM and not just certain zones within PJM), the FERC required PJM to retain a key element of its previous MOPR structure, the unit-specific exemption, an element that Exelon had supported removing. Several entities, including two capacity suppliers that Exelon has been working with sought rehearing of that order.

In May 2013 (based on the MOPR provisions the FERC approved earlier that month), PJM announced the results of its capacity auction covering the delivery year ending May 31, 2017. Exelon is working with PJM stakeholders on several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sanctioned subsidy contracts) cannot inappropriately affect capacity auction prices in PJM.

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, 2017 occurred in May 2013.

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 through rulemaking no later than September 6, 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 licensing issues, including: (1) water quality, (2) fish passage and habitat, and (3) sediment. On August 29, 2013, Exelon filed a water quality certification application pursuant to Section 401 of the Clean Water Act with PA DEP for Muddy Run, addressing these and other issues. The FERC extended the deadline to December 15, 2013 to file a water quality certification application pursuant to Section 401 of the Clean Water Act with the MDE for Conowingo. The stations are being depreciated over their useful lives, which includes the license renewal period. Although Generation expects that these licenses will be renewed, it cannot predict the conditions that may be imposed. Resolution of these issues may require a substantial increase in capital expenditures or may result in increased operating costs and significantly affect Generation s results of operations or financial position. 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 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.

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

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

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

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO and BGE as of September 30, 2013 and December 31, 2012. For additional information on the specific regulatory assets and liabilities, refer to Note 3 Regulatory Matters of the Exelon 2012 Form 10-K.

September 30, 2013	**Exelon**		**ComEd**		**PECO**		**BGE**	
	Current	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**
Regulatory assets								
Pension and other postretirement benefits	$ 308	$ 3,542	$	$	$	$	$	$
Deferred income taxes	12	1,424	3	65		1,296	9	63
AMI programs	4	129	4	29		48		52
AMI meter events		5				5		
Under-recovered distribution service costs	129	275	129	275				
Debt costs	12	60	9	56	3	4	1	9
Fair value of BGE long-term debt(a)		225						
Fair value of BGE supply contract(b)	29	3						
Severance	23	13	19				4	13
Asset retirement obligations		93		68		25		
MGP remediation costs	47	210	40	175	6	34	1	1
RTO start-up costs	2	1	2	1				
Under-recovered uncollectible accounts		31		31				
Renewable energy and associated RECs	16	106	16	106				
Energy and transmission programs	79		79					
Deferred storm costs	3	4					3	4
Electric generation-related regulatory asset	13	33					13	33
Rate stabilization deferral	68	175					68	175
Energy efficiency and demand response programs	75	144					75	144
Merger integration costs(c)	1	10					1	10
Under-recovered electric revenue decoupling(f)	8						8	
Other	48	26	34	13	13	7	1	5
Total regulatory assets	$ 877	$ 6,509	$ 335	$ 819	$ 22	$ 1,419	$ 184	$ 509

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

September 30, 2013	**Exelon**		**ComEd**		**PECO**		**BGE**	
	Current	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**
Regulatory liabilities								
Nuclear decommissioning	$	$ 2,593	$	$ 2,184	$	$ 409	$	$
Removal costs	103	1,420	82	1,202			21	218
Energy efficiency and demand response programs	85		49		36			
DLC Program Costs	1	10			1	10		
Energy efficiency Phase 2		14				14		
Electric distribution tax repairs	20	119			20	119		
Gas distribution tax repairs	8	40			8	40		
Energy and transmission programs	41	7		7	39(d)		2(h)	
Over-recovered gas and electric universal service fund costs	7				7			
Revenue subject to refund(e)	40		40					
Over-recovered gas revenue decoupling(f)	8						8	
Other	1	1						
Total regulatory liabilities	$ 314	$ 4,204	$ 171	$ 3,393	$ 111	$ 592	$ 31	$ 218

December 31, 2012	**Exelon**		**ComEd**		**PECO**		**BGE**	
	Current	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**	**Current**	**Noncurrent**
Regulatory assets								
Pension and other postretirement benefits	$ 304	$ 3,673	$	$	$	$	$	$
Deferred income taxes	14	1,382	5	62		1,255	9	65
AMI programs	3	70	3	10		29		31
AMI meter events		17				17		
Under-recovered distribution service costs	18	191	18	191				
Debt costs	14	68	11	62	3	6	1	9
Fair value of BGE long-term debt(a)		256						
Fair value of BGE supply contract(b)	77	12						
Severance	29	28	25	12			4	16
Asset retirement obligations		90		65		25		
MGP remediation costs	58	232	51	197	6	33	1	2
RTO start-up costs	3	2	3	2				
Under-recovered electric universal service fund costs	11				11			
Financial swap with Generation			226					
Renewable energy and associated RECs	18	49	18	49				
Energy and transmission programs	43		14		1(g)		28(h)	
DSP Program costs	1	3			1	3		
DSP II Program costs	1	2			1	2		
Deferred storm costs	3	6					3	6
Electric generation-related regulatory asset	16	40					16	40
Rate stabilization deferral	67	225					67	225
Energy efficiency and demand response programs	56	126					56	126
Under-recovered electric revenue decoupling(f)	5						5	
Other	23	25	14	16	9	8		2

Total regulatory assets	$ 764	$ 6,497	$ 388	$ 666	$ 32	$ 1,378	$ 190	$ 522

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

December 31, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Nuclear decommissioning	$	$ 2,397	$	$ 2,037	$	$ 360	$	$
Removal costs	97	1,406	75	1,192			22	214
Energy efficiency and demand response programs	131		43		88			
Electric distribution tax repairs	20	132			20	132		
Gas distribution tax repairs	8	46			8	46		
Over-recovered uncollectible accounts	6		6					
Energy and transmission programs	54		6		48(d)			
Over-recovered gas universal service fund costs	3				3			
Over-recovered AEPS costs	2				2			
Revenue subject to refund(e)	40		40					
Over-recovered gas revenue decoupling(f)	7						7	
Total regulatory liabilities	$ 368	$ 3,981	$ 170	$ 3,229	$ 169	$ 538	$ 29	$ 214

(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 11 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) Relates to integration costs to achieve distribution synergies related to the merger transaction.
(d) Includes $18 million related to the DSP program, $13 million related to the over-recovered natural gas costs under the PGC and $8 million related to over-recovered electric transmission costs as of September 30, 2013. As of December 31, 2012, includes $47 million related to the over-recovered electric supply costs under the GSA and $1 million related to the over-recovered natural gas costs under the PGC.
(e) Primarily represents the regulatory liability for revenue subject to refund recorded pursuant to the ICC s order in the 2007 Rate Case. See above for discussion regarding the 2007 Rate Case.
(f) Represents the electric and gas distribution costs recoverable from or refundable to customers under BGE s decoupling mechanism.
(g) Relates to under-recovered transmission costs.
(h) Relates to $2 million of over-recovered natural electric supply costs as of September 30, 2013. As of December 31, 2012, includes $9 million of under-recovered electric supply costs and $19 million of under-recovered natural gas supply costs.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers. For retail suppliers participating in the utilities consolidated billing, ComEd, PECO and BGE must purchase their customer accounts receivables. ComEd and BGE purchase receivables at a discount to primarily recover uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and permitted to recover uncollectible accounts expense from customers through distribution rates. Exelon, ComEd, PECO and BGE do not record unbilled commodity receivables under the POR programs. Purchased billed receivables are classified in Other accounts receivable, net on Exelon s, ComEd s, PECO s and BGE s Consolidated Balance Sheets. The following tables provide information about the purchased receivables of the Registrants as of September 30, 2013 and December 31, 2012.

As of September 30, 2013	**Exelon**	**ComEd**	**PECO**	**BGE**
Purchased receivables(a)	$ 285	$ 124	$ 78	$ 83
Allowance for uncollectible accounts(b)	(31)	(18)	(7)	(6)
Purchased receivables, net	$ 254	$ 106	$ 71	$ 77

As of December 31, 2012	**Exelon**	**ComEd**	**PECO**	**BGE**
Purchased receivables(a)	$ 191	$ 55	$ 65	$ 71
Allowance for uncollectible accounts(b)	(21)	(9)	(6)	(6)
Purchased receivables, net	$ 170	$ 46	$ 59	$ 65

(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's total equity in earnings (losses) on the investment in CENG is as follows:

	Three Months Ended September 30, 2013	**Three Months Ended September 30, 2012**
Equity investment income	$ 68	$ 58
Amortization of basis difference in CENG	(31)	(57)
Total equity in earnings CENG	$ 37	$ 1

	Nine Months Ended September 30, 2013	For the Period March 12, through September 30, 2012
Equity investment income (loss)	$ 93	$ 53
Amortization of basis difference in CENG	(88)	(131)
Total equity in earnings (losses) CENG	$ 5	$ (78)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of March 12, 2012, Generation had an initial basis difference of approximately $204 million between the initial carrying value of its investment in CENG and its underlying equity in CENG. This basis difference resulted from the requirement to record the investment in CENG at fair value under purchase accounting while the underlying assets and liabilities within CENG continue to be accounted for on a historical cost basis. Generation is amortizing this basis difference over the respective useful lives of the assets and liabilities of CENG or as those assets and liabilities affect the earnings of CENG.

Based on tax sharing provisions contained in the operating agreement for CENG, Generation may be eligible for distributions from its investment in CENG in excess of its 50.01% ownership interest. Through purchase accounting, Generation has recorded the fair value of expected future distributions. When these distributions are realized, Generation will record a reduction in its investment in CENG. Any distributions in excess of Generation s investment in CENG would be recorded in earnings.

Related Party Transactions (Exelon and Generation)

CENG

Generation has an agreement under which it is purchasing 85% of the output of CENG s nuclear plants that is not sold to third parties under pre-existing firm and unit contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit contingent basis 50.01% of the output of CENG s nuclear plants, and EDF will purchase on a unit contingent basis 49.99% of the output.

In addition to the PPA, Generation has a power services agency agreement (PSAA) with the CENG plants, which expires on December 31, 2014. The PSAA is a five-year agreement under which Generation provides scheduling, asset management and billing services to the CENG plants for a specified monthly fee. The charges for services reflect the cost of the services.

In addition to the PSAA, Exelon has a shared services agreement (SSA) with CENG, which expires in 2017. Pursuant to an agreement between Exelon and EDF, the pricing in the SSA for services reflect actual costs determined on the same basis that BSC charges its affiliates for similar services subject to an annual cap for most SSA services provided.

The affect of transactions under these agreements on Exelon s and Generation s Consolidated Financial Statements is summarized below:

Agreement	Income/(Expense) Three Months Ended September 30, 2013	Income/(Expense) Nine Months Ended September 30, 2013	Income Statement Classification	Accounts Receivable/ (Accounts Payable) At September 30, 2013
PPA	$ (269)	$ (748)	Purchased power and fuel	$ (76)
PSAA	1	3	Operating revenues	
SSA	10	32	Operating revenues	4

Agreement	Income/(Expense) Three Months Ended September 30, 2012	Income/(Expense) For the Period March 12 through September 30, 2012	Income Statement Classification	Accounts Receivable/ (Accounts Payable) At September 30, 2012
PPA	$ (282)	$ (541)	Purchased power and fuel	$ (86)
PSAA	1	2	Operating revenues	
SSA	14	30	Operating revenues	5

On July 29, 2013, Exelon, Generation and subsidiaries of Generation entered into a Master Agreement with EDF, EDF Inc. (EDFI) (a subsidiary of EDF) and CENG. The Master Agreement contemplates that the parties will execute a series of additional agreements at a closing that will occur following the receipt of regulatory approvals and the satisfaction of other customary closing conditions. Exelon currently expects that the closing will occur late in the first quarter or early in the second quarter of 2014.

At the closing, Generation, CENG and subsidiaries of CENG will execute a Nuclear Operating Services Agreement 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. CENG will reimburse Generation for its direct and allocated costs for such services. The Nuclear Operating Services Agreement will replace the SSA. In addition, at the closing the PSAA will be amended and extended until the complete and permanent cessation of operation of the CENG generation plants.

At closing, Generation will make a $400 million loan to CENG bearing interest at 5.25% per annum, payable out of specified available cash flows of CENG. Immediately following receipt of the proceeds of such loan, CENG will make a $400 million special distribution to EDFI. The parties will also execute a Fourth Amended and Restated Operating Agreement for CENG, pursuant to which, among other things, CENG will commit to make preferred distributions to Generation (after repayment of the $400 million loan) 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 the date of the special distribution to EDFI.

Generation and EDFI will also enter into a Put Option Agreement at closing pursuant to which EDFI will have the option, exercisable beginning in 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 Nuclear Operating Services Agreement. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

Generation will execute an Indemnity Agreement pursuant to which Generation will 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 will guarantee Generation s obligations under this indemnity.

Currently, Exelon and Generation account for its investment in CENG under the equity method of accounting. The transfer of the operating licenses and corresponding operational control to Exelon and Generation will result in Exelon and Generation being required to consolidate the financial position and results of operations of CENG. When that accounting change occurs, Exelon and Generation will derecognize its equity method investment in CENG and will record all assets, liabilities and the non-controlling interest in CENG at fair value on Exelon and Generation s balance sheets. Any difference between the former carrying value and newly recorded fair value at that date will be recognized as a gain or loss upon consolidation, which could be material to Exelon s and Generation s results of operations.

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

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 has been 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 of 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 12 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 require the lessees to return the leasehold interests or to arrange for a third party to bid on a service contract for a period following the lease term. If Exelon chooses the service contract option, the leasehold interests will be returned to Exelon at the end of the term of the service contract. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon s exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. In the fourth quarter of 2000, under the terms of the lease agreements, UII received a prepayment of $1.2 billion for all rent, which reduced the investment in the leases. There are no minimum scheduled lease payments to be received over the remaining term of the leases.

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

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 value. Exelon estimates the fair value of the residual value of its direct financing lease investments under the income approach, which uses a discounted cash flow analysis, which takes into consideration 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 review performed in the second quarter of 2013, the estimated residual value of one of Exelon s direct financing leases experienced an other than temporary decline given reduced long-term energy and capacity price expectations. As a result, Exelon recorded a $14 million pre-tax impairment charge in the second quarter of 2013, which was recorded in investments and operating and maintenance in the Consolidated Balance Sheet and the Consolidated Statements 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.

As of December 31, 2012, Exelon concluded that the estimated fair values of the residual values at the end of the lease terms exceeded the residual values established at the lease dates.

At September 30, 2013 and December 31, 2012, the components of the net investment in long-term leases were as follows:

	September 30, 2013	December 31, 2012
Estimated residual value of leased assets	$ 1,465	$ 1,492
Less: unearned income	774	807
Net investment in long-term leases	$ 691	$ 685

8. Goodwill (Exelon and ComEd)

Goodwill

Under the authoritative guidance for the accounting for goodwill, ComEd is required to perform an assessment for possible impairment of its goodwill at least annually or more frequently if an event occurs that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount. Management concluded the remeasurement of the like-kind exchange position and the charge to ComEd s earnings in the first quarter of 2013 triggered an interim goodwill impairment assessment and, as a result, ComEd tested its goodwill for impairment as of January 31, 2013.

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

The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required. Consistent with prior impairment tests, the estimated fair value of ComEd was determined using a weighted combination of a discounted cash flow analysis and a market multiples analysis. The discounted cash flow analysis relies on a single scenario reflecting base case or management s best estimate of projected cash flows for ComEd s business. The discounted cash flow analysis used in the interim goodwill impairment assessment reflected Exelon s indemnity to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts related to the like-kind exchange position on ComEd s equity.

While the interim assessment indicated no impairment of ComEd s goodwill, certain assumptions used to estimate the fair value of ComEd are highly sensitive to changes. Adverse regulatory actions, such as the early termination of EIMA or changes in significant assumptions, including the discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd s business, and the fair value of debt, could potentially result in a future impairment of ComEd s goodwill, which could be material. Based on the results of the interim goodwill test, the estimated fair value of ComEd would have needed to decrease by more than 10 percent for ComEd to fail the first step of the impairment test.

ComEd s 2013 annual goodwill impairment test is being performed as of November 1, 2013.

9. 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, trust preferred securities (long-term debt to financing trusts or junior subordinated debentures), and preferred securities as of September 30, 2013 and December 31, 2012:

Exelon

	September 30, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 217	$ 3	$ 214	$	$ 217
Long-term debt (including amounts due within one year)	19,565		19,203	1,065	20,268
Long-term debt to financing trusts	648			631	631
SNF obligation	1,021		782		782

	December 31, 2012				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 214	$ 4	$ 210	$	$ 214
Long-term debt (including amounts due within one year)	18,745		20,244	276	20,520
Long-term debt to financing trusts	648			664	664
SNF obligation	1,020		763		763
Preferred securities of subsidiary	87		82		82

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Generation

	September 30, 2013				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 21	$	$ 21	$	$ 21
Long-term debt (including amounts due within one year)	7,809		6,744	1,047	7,791
SNF obligation	1,021		782		782

	December 31, 2012				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 7,483	$	$ 7,591	$ 258	$ 7,849
SNF obligation	1,020		763		763

ComEd

	September 30, 2013				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 153	$	$ 153	$	$ 153
Long-term debt (including amounts due within one year)	5,674		6,240	17	6,257
Long-term debt to financing trust	206			195	195

	December 31, 2012				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 5,567	$	$ 6,530	$ 18	$ 6,548
Long-term debt to financing trust	206			212	212

PECO

	September 30, 2013				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 2,496	$	$ 2,678	$	$ 2,678
Long-term debt to financing trusts	184			182	182

	December 31, 2012				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 210	$	$ 210	$	$ 210
Long-term debt (including amounts due within one year)	1,947		2,264		2,264
Long-term debt to financing trusts	184			188	188
Preferred securities	87		82		82

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

BGE

		September 30, 2013			
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 43	$ 3	$ 40	$	$ 43
Long-term debt (including amounts due within one year)	2,045		2,204		2,204
Long-term debt to financing trusts	258			254	254

		December 31, 2012			
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 2,178	$	$ 2,468	$	$ 2,468
Long-term debt to financing trusts	258			263	263

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of short-term borrowings (Level 2), short-term notes payable related to PECO s accounts receivable agreement (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. See Note 11 Debt and Credit Agreements for additional information on PECO s accounts receivable agreement.

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

The fair value of 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-back 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.

The Registrants also have tax-exempt debt (Level 3). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (i.e., political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above.

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.

Preferred Securities. The fair value of these securities is determined based on the last closing price prior to quarter end, less accrued interest. The securities are registered with the SEC and are public. PECO redeemed all outstanding series of preferred securities on May 1, 2013. See Note 17 Earnings Per Share and Equity for additional information.

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 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, investments priced using an alternative pricing mechanism, and middle market lending using third party valuations.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 September 30, 2013 and December 31, 2012:

As of September 30, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents(a)	$ 1	$	$	$ 1
Nuclear decommissioning trust fund investments				
Cash equivalents	558			558
Equity				
Individually held	1,600			1,600
Exchange traded funds	110			110
Commingled funds		2,114		2,114
Equity funds subtotal	1,710	2,114		3,824
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	938			938
Debt securities issued by states of the United States and political subdivisions of the states		295		295
Debt securities issued by foreign governments		84		84
Corporate debt securities		1,712		1,712
Federal agency mortgage-backed securities		16		16
Commercial mortgage-backed securities (non-agency)		41		41
Residential mortgage-backed securities (non-agency)		7		7
Mutual funds		29		29
Fixed income subtotal	938	2,184		3,122
Middle market lending			245	245
Other debt obligations		14		14
Nuclear decommissioning trust fund investments subtotal(b)	3,206	4,312	245	7,763
Pledged assets for Zion Station decommissioning				
Cash equivalents		25		25
Equity				
Individually held	4			4
Equity funds subtotal	4			4
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	89	7		96
Debt securities issued by states of the United States and political subdivisions of the states		24		24
Corporate debt securities		217		217

Federal agency mortgage-backed securities		7		7
Fixed income subtotal	89	255		344
Middle market lending			106	106
Pledged assets for Zion Station decommissioning subtotal(c)	93	280	106	479

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of September 30, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Rabbi trust investments				
Cash equivalents	2			2
Mutual funds(d)(e)	49			49
Rabbi trust investments subtotal	51			51
Commodity derivative assets				
Economic hedges	540	2,541	703	3,784
Proprietary trading	666	1,184	174	2,024
Effect of netting and allocation of collateral(f)	(1,251)	(2,785)	(311)	(4,347)
Commodity derivative assets subtotal	(45)	940	566	1,461
Interest rate and foreign currency derivative assets	34	49		83
Effect of netting and allocation of collateral	(33)	(2)		(35)
Interest rate and foreign currency derivative assets subtotal	1	47		48
Other investments	1		11	12
Total assets	3,308	5,579	928	9,815
Liabilities				
Commodity derivative liabilities				
Economic hedges	(764)	(1,718)	(363)	(2,845)
Proprietary trading	(686)	(1,135)	(155)	(1,976)
Effect of netting and allocation of collateral(f)	1,359	2,843	291	4,493
Commodity derivative liabilities subtotal(h)	(91)	(10)	(227)	(328)
Interest rate and foreign currency derivative liabilities	(34)	(17)		(51)
Effect of netting and allocation of collateral	33	2		35
Interest rate and foreign currency derivative liabilities subtotal	(1)	(15)		(16)
Deferred compensation obligation		(108)		(108)
Total liabilities	(92)	(133)	(227)	(452)
Total net assets	$ 3,216	$ 5,446	$ 701	$ 9,363

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 995	$	$	$ 995
Nuclear decommissioning trust fund investments				
Cash equivalents	245			245
Equity				
Individually held	1,480			1,480
Commingled funds		1,933		1,933
Equity funds subtotal	1,480	1,933		3,413
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057			1,057
Debt securities issued by states of the United States and political subdivisions of the states		321		321
Debt securities issued by foreign governments		93		93
Corporate debt securities		1,788		1,788
Federal agency mortgage-backed securities		24		24
Commercial mortgage-backed securities (non-agency)		45		45
Residential mortgage-backed securities (non-agency)		11		11
Mutual funds		23		23
Fixed income subtotal	1,057	2,305		3,362
Middle market lending			183	183
Other debt obligations		15		15
Nuclear decommissioning trust fund investments subtotal(b)	2,782	4,253	183	7,218
Pledged assets for Zion decommissioning				
Cash equivalents		23		23
Equity				
Individually held	14			14
Commingled funds		9		9
Equity funds subtotal	14	9		23
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12		130
Debt securities issued by states of the United States and political subdivisions of the states		37		37
Corporate debt securities		249		249
Federal agency mortgage-backed securities		49		49
Commercial mortgage-backed securities (non-agency)		6		6
Fixed income subtotal	118	353		471
Middle market lending			89	89
Other debt obligations		1		1

Pledged assets for Zion Station decommissioning subtotal(c)	132	386	89	607
Rabbi trust investments				
Cash equivalents	2			2
Mutual funds(d)(e)	69			69
Rabbi trust investments subtotal	71			71

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of December 31, 2012	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivative assets				
Economic hedges	861	3,173	641	4,675
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral(f)	(1,823)	(4,175)	(58)	(6,056)
Commodity derivative assets subtotal(g)	80	1,076	656	1,812
Interest rate and foreign currency derivative assets		114		114
Effect of netting and allocation of collateral		(51)		(51)
Interest rate and foreign currency derivative assets subtotal		63		63
Other Investments	2		17	19
Total assets	4,062	5,778	945	10,785
Liabilities				
Commodity derivative liabilities				
Economic hedges	(1,041)	(2,289)	(236)	(3,566)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)
Effect of netting and allocation of collateral(f)	2,042	4,020	25	6,087
Commodity derivative liabilities subtotal(g)(h)	(83)	(228)	(289)	(600)
Interest rate and foreign currency derivative liabilities		(84)		(84)
Effect of netting and allocation of collateral		51		51
Interest rate and foreign currency derivative liabilities subtotal		(33)		(33)
Deferred compensation obligation		(102)		(102)
Total liabilities	(83)	(363)	(289)	(735)
Total net assets	$ 3,979	$ 5,415	$ 656	$ 10,050

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.

(b) Excludes net assets of $13 million and $30 million at September 30, 2013 and December 31, 2012, 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 September 30, 2013 and December 31, 2012. 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 $49 million related to deferred compensation at September 30, 2013, and $53 million related to deferred compensation and $16 million related to Supplemental Executive Retirement Plan at December 31, 2012. .

(e) Excludes $30 million and $28 million of the cash surrender value of life insurance investments at September 30, 2013 and December 31, 2012, respectively.

(f) Includes collateral postings (received) from counterparties. Collateral posted (received) from counterparties, net of collateral paid to counterparties, totaled $108 million, $58 million and $(20) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of September 30, 2013. Collateral posted (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012.

(g) The Level 3 balance does not include current assets for Generation and current liabilities for ComEd of $226 million at December 31, 2012, related to the fair value of Generation s financial swap contract with ComEd.

(h) The Level 3 balance includes the current and noncurrent liability of $16 million and $106 million at September 30, 2013, respectively, and $18 million and $49 million at December 31, 2012, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2013 and 2012:

Three Months Ended September 30, 2013	**Nuclear Decommissioning Trust Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total**
Balance as of June 30, 2013	$ 240	$ 111	$ 431	$ 11	$ 793
Total realized / unrealized losses					
Included in net income			(32)(a)		(32)
Included in other comprehensive income					
Included in regulatory assets	(1)		(37)		(38)
Included in payable for Zion Station decommissioning					
Change in collateral			(30)		(30)
Purchases, sales, issuances and settlements					
Purchases	23	10	8		41
Sales	(14)	(15)			(29)
Settlements	(3)				(3)
Transfers into Level 3			4		4
Transfers out of Level 3			(5)		(5)
Balance as of September 30, 2013	$ 245	$ 106	$ 339	$ 11	$ 701
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the three months ended September 30, 2013	$	$	$ 51	$	$ 51

Nine Months Ended September 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	$ 367	$ 17	$ 656
Total realized / unrealized gains (losses)					
Included in net income	2		(1)(a)		1
Included in other comprehensive income					
Included in regulatory assets	8		(55)(b)		(47)
Included in payable for Zion Station decommissioning		1			1
Change in collateral			13		13
Purchases, sales, issuances and settlements					
Purchases	90	43	16	2	151
Sales	(27)	(27)	(8)	(8)	(70)
Settlements	(11)				(11)
Transfers into Level 3			11		11
Transfers out of Level 3			(4)		(4)
Balance as of September 30, 2013	$ 245	$ 106	$ 339	$ 11	$ 701

The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the nine months ended September 30, 2013	$	1	$		$	159	$	$ 160

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(a) Includes the reclassification of $83 million and $160 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and nine months ended September 30, 2013.
(b) Excludes decreases in fair value of $11 million and realized losses reclassified due to settlements of $215 million associated with Generation s financial swap contract with ComEd for the nine months ended September 30, 2013. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

Three Months Ended September 30, 2012	**Nuclear Decommissioning Trust Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total**
Balance as of June 30, 2012	$ 54	$ 59	$ 295	$ 17	$ 425
Total realized / unrealized gains (losses)					
Included in net income			(97)(a)		(97)
Included in other comprehensive income					
Included in regulatory assets	2		41(b)		43
Included in payable for Zion Station decommissioning		1			1
Change in collateral			(15)		(15)
Purchases, sales, issuances and settlements					
Purchases	14	4			18
Sales					
Transfers into Level 3					
Transfers out of Level 3					
Balance as of September 30, 2012	$ 70	$ 64	$ 224	$ 17	$ 375
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 September 30, 2012	$	$	$ (42)	$	$ (42)

Nine Months Ended September 30, 2012	**Nuclear Decommissioning Trust Fund Investments**	**Pledged Assets for Zion Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total**
Balance as of December 31, 2011	$ 13	$ 37	$ 17	$	$ 67
Total realized / unrealized gains (losses)					
Included in net income			(78)(a)		(78)
Included in other comprehensive income					
Included in regulatory assets	2		36(b)		38
Included in payable for Zion Station decommissioning					
Change in collateral			(7)		(7)
Purchases, sales, issuances and settlements					
Purchases	55	36	329(c)	17	437
Sales		(9)			(9)
Transfers into Level 3			(34)		(34)
Transfers out of Level 3			(39)		(39)

Balance as of September 30, 2012	$	70	$	64	$	224	$	17	$ 375
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the nine months ended September 30, 2012	$		$		$	62	$		$ 62

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(a) Includes the reclassification of $55 million and $140 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and nine months ended September 30, 2012, respectively.
(b) Excludes $35 million of decreases in fair value and $86 million of increases in fair value and $119 million and $427 million of realized losses due to settlements for the three and nine months ended September 30, 2012 of Generation s financial swap contract with ComEd, which eliminates upon consolidation in Exelon s Consolidated Financial Statements.
(c) Includes $310 million of fair value from contracts and $14 million of other investments acquired as a result of the merger.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2013 and 2012:

	Operating Revenue	Purchased Power and Fuel	Other, net(a)
Total gains (losses) included in income for the three months ended September 30, 2013	$ (39)	$ 7	$
Total gains (losses) included in income for the nine months ended September 30, 2013	$ (61)	$ 60	$ 2
Change in the unrealized gains relating to assets and liabilities held for the three months ended September 30, 2013	$ 42	$ 9	$
Change in the unrealized gains relating to assets and liabilities held for the nine months ended September 30, 2013	$ 81	$ 78	$ 1

	Operating Revenue	Purchased Power and Fuel	Other, net
Total gains (losses) included in income for the three months ended September 30, 2012	$ (101)	$ 4	$
Total losses included in income for the nine months ended September 30, 2012	$ (78)	$	$
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2012	$ (43)	$ 1	$
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2012	$ 82	$ (20)	$

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

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 September 30, 2013 and December 31, 2012:

As of September 30, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 674	$	$	$ 674
Nuclear decommissioning trust fund investments				
Cash equivalents	558			558
Equity				
Individually held	1,600			1,600
Exchange traded funds	110			110
Commingled funds		2,114		2,114
Equity funds subtotal	1,710	2,114		3,824
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	938			938
Debt securities issued by states of the United States and political subdivisions of the states		295		295
Debt securities issued by foreign governments		84		84
Corporate debt securities		1,712		1,712
Federal agency mortgage-backed securities		16		16
Commercial mortgage-backed securities (non-agency)		41		41
Residential mortgage-backed securities (non-agency)		7		7
Mutual funds		29		29
Fixed income subtotal	938	2,184		3,122
Middle market lending			245	245
Other debt obligations		14		14
Nuclear decommissioning trust fund investments subtotal(b)	3,206	4,312	245	7,763
Pledged assets for Zion Station decommissioning				
Cash equivalents		25		25
Equity				
Individually held	4			4
Equity funds subtotal	4			4
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	89	7		96
Debt securities issued by states of the United States and political subdivisions of the states		24		24
Corporate debt securities		217		217

Federal agency mortgage-backed securities		7		7
Fixed income subtotal	89	255		344
Middle market lending			106	106
Pledged assets for Zion Station decommissioning subtotal(c)	93	280	106	479
Rabbi trust investments				
Mutual funds(d)	12			12
Rabbi trust investments subtotal	12			12

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of September 30, 2013	Level 1	Level 2	Level 3	Total
Commodity derivative assets				
Economic hedges	540	2,541	703	3,784
Proprietary trading	666	1,184	174	2,024
Effect of netting and allocation of collateral(e)	(1,251)	(2,785)	(311)	(4,347)
Commodity derivative assets subtotal	(45)	940	566	1,461
Interest rate and foreign currency derivative assets	34	36		70
Effect of netting and allocation of collateral	(33)	(2)		(35)
Interest rate and foreign currency derivative assets subtotal	1	34		35
Other investments	1		11	12
Total assets	3,942	5,566	928	10,436
Liabilities				
Commodity derivative liabilities				
Economic hedges	(764)	(1,718)	(241)	(2,723)
Proprietary trading	(686)	(1,135)	(155)	(1,976)
Effect of netting and allocation of collateral(e)	1,359	2,843	291	4,493
Commodity derivative liabilities subtotal	(91)	(10)	(105)	(206)
Interest rate and foreign currency derivative liabilities	(34)	(17)		(51)
Effect of netting and allocation of collateral	33	2		35
Interest rate and foreign currency derivative liabilities subtotal	(1)	(15)		(16)
Deferred compensation obligation		(27)		(27)
Total liabilities	(92)	(52)	(105)	(249)
Total net assets	$ 3,850	$ 5,514	$ 823	$ 10,187

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 487	$	$	$ 487
Nuclear decommissioning trust fund investments				
Cash equivalents	245			245
Equity				
Individually held	1,480			1,480
Commingled funds		1,933		1,933
Equity funds subtotal	1,480	1,933		3,413

Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057			1,057
Debt securities issued by states of the United States and political subdivisions of the states		321		321
Debt securities issued by foreign governments		93		93
Corporate debt securities		1,788		1,788
Federal agency mortgage-backed securities		24		24
Commercial mortgage-backed securities (non-agency)		45		45
Residential mortgage-backed securities (non-agency)		11		11
Mutual funds		23		23
Fixed income subtotal	1,057	2,305		3,362
Middle market lending			183	183
Other debt obligations		15		15
Nuclear decommissioning trust fund investments subtotal(b)	2,782	4,253	183	7,218

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Pledged assets for Zion Station decommissioning				
Cash equivalents		23		23
Equity				
Individually held	14			14
Commingled funds		9		9
Equity funds subtotal	14	9		23
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12		130
Debt securities issued by states of the United States and political subdivisions of the states		37		37
Corporate debt securities		249		249
Federal agency mortgage-backed securities		49		49
Commercial mortgage-backed securities (non-agency)		6		6
Fixed income subtotal	118	353		471
Middle market lending			89	89
Other debt obligations		1		1
Pledged assets for Zion Station decommissioning subtotal(c)	132	386	89	607
Rabbi trust investments				
Cash equivalents	1			1
Mutual funds(d)	13			13
Rabbi trust investments subtotal	14			14
Commodity derivative assets				
Economic hedges	861	3,173	867	4,901
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral(e)	(1,823)	(4,175)	(58)	(6,056)
Commodity and foreign currency assets subtotal(f)	80	1,076	882	2,038
Interest rate and foreign currency derivative assets		101		101
Effect of netting and allocation of collateral		(51)		(51)
Interest rate and foreign currency derivative assets subtotal		50		50
Other investments	2		17	19
Total assets	3,497	5,765	1,171	10,433
Liabilities				
Commodity derivative liabilities				
Economic hedges	(1,041)	(2,289)	(169)	(3,499)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)

Effect of netting and allocation of collateral(e)	2,042	4,020	25	6,087
Commodity derivative liabilities subtotal	(83)	(228)	(222)	(533)
Interest rate derivative liabilities		(84)		(84)
Effect of netting and allocation of collateral		51		51
Interest rate and foreign currency derivative liabilities		(33)		(33)
Deferred compensation obligation		(28)		(28)
Total liabilities	(83)	(289)	(222)	(594)
Total net assets	$ 3,414	$ 5,476	$ 949	$ 9,839

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net assets of $13 million and $30 million at September 30, 2013 and December 31, 2012, 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 at both September 30, 2013 December 31, 2012. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) Excludes $9 million and $8 million of the cash surrender value of life insurance investments at September 30, 2013 and December 31, 2012, respectively.
(e) Includes collateral postings (received) from counterparties. Collateral posted (received) from counterparties, net of collateral paid to counterparties, totaled $108 million, $58 million and $(20) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of September 30, 2013. Collateral posted (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012.
(f) The level 3 balance includes current assets for Generation of $226 million at December 31, 2012, related to the fair value of Generation s financial swap contract with ComEd, which eliminates upon consolidation in Exelon s Consolidated Financial Statements.

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 nine months ended September 30, 2013 and 2012:

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 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		(8)(a)(b)		(6)
Included in other comprehensive income			(219)(b)		(219)
Included in noncurrent payables to affiliates	8				8
Included in payable for Zion Station decommissioning		1			1
Change in collateral			13		13
Purchases, sales, issuances and settlements					
Purchases	90	43	16	2	151
Sales	(27)	(27)	(8)	(8)	(70)
Settlements	(11)				(11)
Transfers into Level 3			11		11
Transfers out of Level 3			(4)		(4)
Balance as of September 30, 2013	$ 245	$ 106	$ 461	$ 11	$ 823
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the nine months ended September 30, 2013	$ 1	$	$ 148	$	$ 149

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

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

Three Months Ended September 30, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of June 30, 2012	$ 54	$ 59	$ 912	$ 17	$ 1,042
Total realized / unrealized gains (losses)					
Included in net income			(112)(a)		(112)
Included in other comprehensive income			(139)(b)		(139)
Included in noncurrent payables to affiliates	2				2
Included in payable for Zion Station decommissioning		1			1
Changes in collateral			(15)		(15)
Purchases, sales, issuances and settlements					
Purchases	14	4			18
Sales					
Balance as of September 30, 2012	$ 70	$ 64	$ 646	$ 17	$ 797
	$	$	$ (77)	$	$ (77)

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 September 30, 2012

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2011	$ 13	$ 37	$ 817	$	$ 867
Total realized / unrealized gains (losses)					
Included in net income			(109)(a)		(109)
Included in other comprehensive income			(311)(b)		(311)
Included in noncurrent payables to affiliates	2				2
Changes in collateral			(7)		(7)
Purchases, sales, issuances and settlements					
Purchases	55	36	329(c)	17	437
Sales		(9)			(9)
Transfers into Level 3			(34)		(34)
Transfers out of Level 3			(39)		(39)
Balance as of September 30, 2012	$ 70	$ 64	$ 646	$ 17	$ 797
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the nine months ended September 30, 2012	$	$	$ 1	$	$ 1

(a) Includes the reclassification of $35 million and $110 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and nine months ended September 30, 2012, respectively.

(b) Includes $35 million of decreases in fair value and $86 million of increases in fair value and realized losses due to settlements of $119 million and $427 million associated with Generation's financial swap contract with ComEd for the three and nine months ended September 30, 2012, respectively. This position was re-designated as a cash flow hedge prior to the merger date. All prospective changes in fair value and reclassifications of realized amounts are being recorded to income offset by the amortization of the frozen mark in OCI. All items eliminate upon consolidation in Exelon s Consolidated Financial Statements.

(c) Includes $310 million of fair value from contracts and $14 million of other investments acquired as a result of the merger.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2013 and 2012:

	Operating Revenue	Purchased Power and Fuel	Other, net(a)
Total gains (losses) included in net income for the three months ended September 30, 2013	$ (39)	$ 7	$
Total gains (losses) included in net income for the nine months ended September 30, 2013	$ (67)	$ 59	$ 2
Change in the unrealized gains relating to assets and liabilities held for the three months ended September 30, 2013	$ 42	$ 9	$
Change in the unrealized gains relating to assets and liabilities held for the nine months ended September 30, 2013	$ 71	$ 77	$ 1

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Operating Revenue	Purchased Power and Fuel	Other, net
Total gains (losses) included in net income for the three months ended September 30, 2012	$ (116)	$ 4	$
Total losses included in net income for the nine months ended September 30, 2012	$ (109)	$	$
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2012	$ (78)	$ 1	$
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2012	$ 21	$ (20)	$

(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 September 30, 2013 and December 31, 2012:

As of September 30, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$	$	$	$
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)			(122)	(122)
Total liabilities		(8)	(122)	(130)
Total net assets (liabilities)	$ 5	$ (8)	$ (122)	$ (125)

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 111	$	$	$ 111
Rabbi trust investments				
Mutual funds	8			8
Rabbi trust investments subtotal	8			8
Total assets	119			119

Liabilities				
Deferred compensation obligation		(8)		(8)
Mark-to-market derivative liabilities(a)(b)			(293)	(293)
Total liabilities		(8)	(293)	(301)
Total net assets (liabilities)	$ 119	$ (8)	$ (293)	$ (182)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(a) The Level 3 balance includes the current and noncurrent liability of $16 million and $106 million at September 30, 2013, respectively, and $18 million and $49 million at December 31, 2012, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.
(b) The Level 3 balance includes the current liability of $226 million at December 31, 2012, related to the fair value of ComEd's financial swap contract with Generation which eliminated upon consolidation in Exelon's Consolidated Financial Statements.

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 nine months ended September 30, 2013 and 2012:

Three Months Ended September 30, 2013	**Mark-to-Market Derivatives**
Balance as of June 30, 2013	$ (85)
Total realized / unrealized gains included in regulatory assets(b)	(37)
Balance as of September 30, 2013	$ (122)

Nine Months Ended September 30, 2013	**Mark-to-Market Derivatives**
Balance as of December 31, 2012	$ (293)
Total realized / unrealized gains included in regulatory assets(a)(b)	171
Balance as of September 30, 2013	$ (122)

(a) Includes $11 million of decreases in fair value and realized gains due to settlements of $215 million associated with ComEd's financial swap contract with Generation for the nine months ended September 30, 2013. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(b) Includes $37 million and $57 million of increases in the fair value and realized losses due to settlements of $1 million and $5 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three and nine months ended September 30, 2013, respectively.

Three Months Ended September 30, 2012	**Mark-to-Market Derivatives**
Balance as of June 30, 2012	$ (617)
Total realized / unrealized gains included in regulatory assets(a)(b)	195
Balance as of September 30, 2012	$ (422)

Nine Months Ended September 30, 2012	**Mark-to-Market Derivatives**
Balance as of December 31, 2011	$ (800)

Total realized / unrealized gains included in regulatory assets(a)(b)		378
Balance as of September 30, 2012	$	(422)

(a) Includes $35 million of increases in fair value and $86 million of decreases in fair value and realized gains due to settlements of $119 million and $427 million of associated with ComEd's financial swap contract with Generation for the three and nine months ended September 30, 2012, respectively. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

(b) Includes $40 million and $33 million of increases in the fair value and realized losses due to settlements of $1 million and $2 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three and nine months ended September 30, 2012, respectively.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 September 30, 2013 and December 31, 2012:

As of September 30, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$ 583	$	$	$ 583
Rabbi trust investments				
Mutual funds(a)	9			9
Rabbi trust investments subtotal	9			9
Total assets	592			592
Liabilities				
Deferred compensation obligation		(16)		(16)
Total liabilities		(16)		(16)
Total net assets (liabilities)	$ 592	$ (16)	$	$ 576

As of December 31, 2012	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$ 346	$	$	$ 346
Rabbi trust investments				
Mutual funds(a)	9			9
Rabbi trust investments subtotal	9			9
Total assets	355			355
Liabilities				
Deferred compensation obligation		(18)		(18)
Total liabilities		(18)		(18)
Total net assets (liabilities)	$ 355	$ (18)	$	$ 337

(a) Excludes $14 million and $13 million of the cash surrender value of life insurance investments at September 30, 2013 and December 31, 2012, respectively.

PECO had no Level 3 assets or liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2013 and 2012.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 September 30, 2013 and December 31, 2012:

As of September 30, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 53	$	$	$ 53
Rabbi trust investments				
Mutual funds(a)	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, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 33	$	$	$ 33
Rabbi trust investments				
Mutual funds	5			5
Rabbi trust investments subtotal	5			5
Total assets	38			38
Liabilities				
Deferred compensation obligation		(5)		(5)
Total liabilities		(5)		(5)
Total net assets (liabilities)	$ 38	$ (5)	$	$ 33

BGE had no Level 3 assets or liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2013 and 2012.

Valuation Techniques Used to Determine Fair Value

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

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

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to fund Generation 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 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.

With respect to individually held equity securities and exchange traded funds, 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 and exchange traded funds, held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually and exchange traded funds 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.

Equity 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 and Generation invest primarily seek to track the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. In general, equity commingled funds are redeemable daily. Equity and fixed income commingled and mutual funds are categorized in Level 2 because the fair value of the funds are based on NAVs per fund share (the unit of account), primarily derived from the quoted prices in active markets on the underlying equity securities. See Note 13 Nuclear Decommissioning for further discussion on the NDT fund investments.

Middle market lending funds are investments in loans or managed funds which invest in private companies. Generation elected the fair value option for its investments held by 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.

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. The investments are in fixed-income commingled funds and mutual funds, including short-term investment 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. Fixed-income commingled funds and mutual funds, such as money market 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.

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.

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 10 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 in Level 2 in the fair value hierarchy.

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

Mark-to-Market Derivatives (Exelon, Generation, ComEd). For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon s RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon s business units. The RMC reports to the Exelon Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at Exelon. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

Disclosed below is detail surrounding the Registrants significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and notional size. 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 highly 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 generally less than $1.96 and $0.18 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.

(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 10 Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk. The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade		Fair Value at September 30, 2013(c)	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives	Economic Hedges (Generation)(a)	$ 462	Discounted Cash Flow	Forward power price	$15 - $103
				Forward gas price	$3.51 - $5.97
			Option Model	Volatility percentage	27% - 107%
Mark-to-market derivatives	Proprietary trading (Generation)(a)	$ 19	Discounted Cash Flow	Forward power price	$14 - $103
			Option Model	Volatility percentage	14% - 28%
Mark-to-market derivatives (ComEd)		$ (122)	Discounted Cash Flow	Forward heat rate(b)	8 - 9
				Marketability reserve	3.5% - 8%
				Renewable factor	84% - 130%

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 $20 million as of September 30, 2013.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Type of trade		Fair Value at December 31, 2012(d)	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives	Economic Hedges (Generation)(a)	$ 473	Discounted Cash Flow	Forward power price	$14 - $79
				Forward gas price	$3.26 - $6.27
			Option Model	Volatility percentage	28% - 132%
Mark-to-market derivatives	Proprietary trading (Generation)(a)	$ (6)	Discounted Cash Flow	Forward power price	$15 - $106
			Option Model	Volatility percentage	16% - 48%
Mark-to-market derivatives	Transactions with Affiliates (Generation and ComEd)(b)	$ 226	Discounted Cash Flow	Marketability reserve	8% - 9%
Mark-to-market derivatives (ComEd)		$ (67)	Discounted Cash Flow	Forward heat rate(c)	8 - 9.5
				Marketability reserve	3.5% - 8.3%
				Renewable factor	81% - 123%

a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
b) Includes current assets for Generation and current liabilities for ComEd of $226 million, related to the fair value of the five-year financial swap contract between Generation and ComEd, which eliminates in consolidation.
c) 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.
d) The fair values do not include cash collateral held on level three positions of $33 million as of December 31, 2012.

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, the fair value of these loans is determined using a combination of valuations 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 applications of discounts or premiums applied to the prices of comparable companies for factors such as size, marketability and relative performance.

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its middle market lending, 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 middle market lending, Generation reviewed independent valuations and reviewed the assumptions in the detailed pricing models used by the fund managers.

As of September 30, 2013, Generation has outstanding commitments to invest in middle market lending of approximately $192 million. These commitments will be funded by Generation s existing nuclear decommissioning trust funds.

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

The Registrants are exposed to certain risks related to ongoing business operations. The primary risks managed by using derivative instruments are commodity price risk and interest rate risk.

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 19 Commitments and Contingencies of the Exelon 2012 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. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power 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 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 September 30, 2013, the percentage of expected generation hedged for the major reportable segments was 97%-100%, 84%-87%, and 48%-51% for 2013, 2014, and 2015, 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.

In order to fulfill a requirement of the Illinois Settlement Legislation, Generation and ComEd entered into a five-year financial swap contract that expired May 31, 2013. The financial swap was designed to hedge spot market purchases, which, along with ComEd s remaining energy procurement contracts, met its load service requirements. The terms of the financial swap contract required Generation to pay the around-the-clock market price for a portion of ComEd s electricity supply requirement, while ComEd paid a fixed price.

As the contract expired May 31, 2013, all realized impacts have been included in Generation s and ComEd s results of operations. In Exelon s consolidated financial statements, all financial statement effects of the financial swap recorded by Generation and ComEd are eliminated.

In addition, the physical contracts that Generation has entered into with ComEd and that ComEd has entered into with Generation and other suppliers as part of the ComEd power procurement process, which are further discussed in Note 3 Regulatory Matters of the Exelon 2012 Form 10-K qualify and are accounted for under the NPNS exception. Based on the Illinois Settlement Legislation and ICC-approved procurement methodologies permitting ComEd to recover its electricity procurement costs from retail customers with no mark-up, ComEd s price risk related to power procurement is limited.

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 associate RECs were reduced in the first quarter of 2013. 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 5 Regulatory Matters for additional information.

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

PECO s natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply reliability at the least cost. PECO s reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO s natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 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%,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 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 2,499 GWhs and 6,066 GWhs for the three and nine months ended September 30, 2013, respectively, and 4,352 GWhs and 9,981 GWhs for the three and nine months ended September 30, 2012, 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 September 30, 2013, Exelon had $1,250 million of notional amounts of fixed-to-floating hedges outstanding and $213 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $1 million decrease in Exelon Consolidated pre-tax income for the nine months ended September 30, 2013. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. Below is a summary of the interest rate and foreign currency hedges as of September 30, 2013.

	Generation					Other	Exelon
Description	**Derivatives Designated as Hedging Instruments**	**Economic Hedges**	**Proprietary Trading (a)**	**Collateral and Netting (b)**	**Subtotal**	**Derivatives Designated as Hedging Instruments**	**Total**
Mark-to-market derivative assets (Current Assets)	$	$ 3	$ 18	$ (19)	$ 2	$	$ 2
Mark-to-market derivative assets (Noncurrent Assets)	27	5	17	(16)	33	13	46
Total mark-to-market derivative assets	$ 27	$ 8	$ 35	$ (35)	$ 35	$ 13	$ 48
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (1)	$ (19)	$ 19	$ (2)	$	$ (2)
Mark-to-market derivative liabilities (Noncurrent liabilities)	(14)		(16)	16	(14)		(14)
Total mark-to-market derivative liabilities	$ (15)	$ (1)	$ (35)	$ 35	$ (16)	$	$ (16)
Total mark-to-market derivative net assets (liabilities)	$ 12	$ 7	$	$	$ 19	$ 13	$ 32

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(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 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.

The following table provides a summary of the interest rate hedge balances recorded by the Registrants as of December 31, 2012:

	Generation					Other	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	$ 20	$ (19)	$ 4	$	$ 4
Mark-to-market derivative assets (Noncurrent Assets)	38	8	32	(32)	46	13	59
Total mark-to-market derivative assets	$ 38	$ 11	$ 52	$ (51)	$ 50	$ 13	$ 63
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (1)	$ (19)	$ 19	$ (2)	$	$ (2)
Mark-to-market derivative liabilities (Noncurrent liabilities)	(31)		(32)	32	(31)		(31)
Total mark-to-market derivative liabilities	(32)	(1)	(51)	51	(33)		(33)
Total mark-to-market derivative net assets (liabilities)	$ 6	$ 10	$ 1	$	$ 17	$ 13	$ 30

(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 interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

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

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

Three Months Ended September 30, 2013				Nine Months Ended September 30, 2013			
Gain (Loss) on Swaps		Gain (Loss) on Borrowings		Gain (Loss) on Swaps		Gain (Loss) on Borrowings	
Generation(a)	Exelon	Generation	Exelon	Generation(a)	Exelon	Generation	Exelon
$(4)	$ 4	$ (1)	$ (5)	$ (13)	$ 1	$	$ (2)

96

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Three Months Ended September 30, 2012				Nine Months Ended September 30, 2012			
Gain (Loss) on Swaps		Gain (Loss) on Borrowings		Gain (Loss) on Swaps		Gain (Loss) on Borrowings	
Generation	Exelon	Generation	Exelon	Generation	Exelon	Generation	Exelon
$(1)	$	$ (3)	$	$ (3)	$ (2)	$ (6)	$ 2

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

During the third quarter of 2013, Exelon entered into $450 million of notional amounts of fixed-to-floating fair value hedges related to interest rate swaps, which expire in 2020. At September 30, 2013, Exelon and Generation had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $1,100 million and $550 million, with unrealized gains of $40 million and $27 million, respectively. At December 31, 2012, Exelon and Generation had outstanding fixed-to-floating fair value hedges related to interest rate swaps of $650 million and $550 million that expire in 2015, with unrealized gains of $49 million and $38 million, respectively. During the nine months ended September 30, 2013 and 2012, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $1 million gain and immaterial, respectively.

Cash Flow Hedges. In anticipation of the Continental Wind, LLC non-recourse project financing that was completed on September 30, 2013, Exelon entered into forward starting interest rate swaps that were designated as cash flow hedges to hedge the change in benchmark interest rates. Upon settlement of the swaps, a $26 million effective gain in OCI was deferred and will be amortized into interest expense over the life of the debt. See Note 11 Debt and Credit Agreements for additional information on the project financing.

In connection with the DOE guaranteed loan for the Antelope Valley acquisition, as discussed in Note 11 Debt and Credit Agreements, 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 April 5, 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 $328 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 $156 million. At September 30, 2013, Generation s mark-to-market non-current derivative liability relating to the interest rate swaps in connection with the loan agreement to fund Antelope Valley was $13 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 $29 million as of September 30, 2013 and expire in 2027. After the closing of the merger with Constellation, the swaps were re-designated as cash flow hedges. At September 30, 2013, the subsidiary had a $2 million non-current 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 $28 million as of September 30, 2013 and expires in 2030. This swap is designated as a cash flow hedge. At September 30, 2013, the subsidiary had a $2 million non-current derivative asset related to the swap.

During the nine months ended September 30, 2013 and 2012, the impact on the results of operations as a result of ineffectiveness from cash flow hedges was immaterial.

Economic Hedges. At September 30, 2013, Generation had $134 million in notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $38 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.

At September 30, 2013, 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 $3 million. These swaps, which were acquired as part of the merger with Constellation, expire in 2014. During the nine months ended September 30, 2013 and the period from March 12 to September 30, 2012, the impact on the results of operations was immaterial.

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 either as the contracts deliver, when collateral is requested or in the event of default. Generation s use of cash collateral is generally unrestricted unless Generation is downgraded below investment grade (i.e. to BB+ or Ba1). In the table below, Generation s energy related economic hedges and proprietary trading derivatives are shown gross and the impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, is aggregated in the collateral and netting column. As of September 30, 2013 and December 31, 2012, $5 million of cash collateral posted and $3 million of cash collateral received, 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.

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 September 30, 2013:

	Generation				ComEd	Exelon
Derivatives	**Economic Hedges**	**Proprietary Trading**	**Collateral and Netting(a)**	**Subtotal (b)**	**Economic Hedges (c)**	**Total Derivatives**
Mark-to-market derivative assets (current assets)	$ 2,244	$ 1,577	$ (3,093)	$ 728	$	$ 728
Mark-to-market derivative assets (noncurrent assets)	1,540	447	(1,254)	733		733
Total mark-to-market derivative assets	$ 3,784	$ 2,024	$ (4,347)	$ 1,461	$	$ 1,461
Mark-to-market derivative liabilities (current liabilities)	$ (1,812)	$ (1,538)	$ 3,242	$ (108)	$ (16)	$ (124)
Mark-to-market derivative liabilities (noncurrent liabilities)	(911)	(438)	1,251	(98)	(106)	(204)
Total mark-to-market derivative liabilities	$ (2,723)	$ (1,976)	$ 4,493	$ (206)	$ (122)	$ (328)
Total mark-to-market derivative net assets (liabilities)	$ 1,061	$ 48	$ 146	$ 1,255	$ (122)	$ 1,133

(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 $86 million and $8 million, respectively, and current and noncurrent liabilities are shown net of collateral of $(235) million and $(5) million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $146 million at September 30, 2013.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2012:

	Generation				ComEd		Exelon
Derivatives	**Economic Hedges(a)**	**Proprietary Trading**	**Collateral and Netting(b)**	**Subtotal (c)**	**Economic Hedges (a)(d)**	**Intercompany Eliminations (a)**	**Total Derivatives**
Mark-to-market derivative assets (current assets)	$ 2,883	$ 2,469	$ (4,418)	$ 934	$	$	$ 934
Mark-to-market derivative assets with affiliate (current assets)	226			226		(226)	
Mark-to-market derivative assets (noncurrent assets)	1,792	724	(1,638)	878			878
Mark-to-market							
Total mark-to-market derivative assets	$ 4,901	$ 3,193	$ (6,056)	$ 2,038	$	$ (226)	$ 1,812
Mark-to-market derivative liabilities (current liabilities)	$ (2,419)	$ (2,432)	$ 4,519	$ (332)	$ (18)	$	$ (350)
Mark-to-market derivative liability with affiliate (current liabilities)					(226)	226	
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,080)	(689)	1,568	(201)	(49)		(250)
Mark-to-market							
Total mark-to-market derivative liabilities	$ (3,499)	$ (3,121)	$ 6,087	$ (533)	$ (293)	$ 226	$ (600)
Total mark-to-market derivative net assets (liabilities)	$ 1,402	$ 72	$ 31	$ 1,505	$ (293)	$	$ 1,212

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $226 million related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above. For Generation excludes $28 million of noncurrent liability relating to an interest rate swap in connection with a loan agreement to fund Antelope Valley as discussed above.

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

(c) Current and noncurrent assets are shown net of collateral of $113 million and $201 million, respectively, and current and noncurrent liabilities are shown net of collateral of $ (214) million and $ (131) million, respectively. The total cash collateral received, net of cash collateral posted and offset against mark-to-market assets and liabilities was $31 million at December 31, 2012.

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

Cash Flow Hedges (Exelon, Generation and ComEd). 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

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

from the date of de-designation. Approximately $271 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 2013 through 2014.

Exelon discontinues hedge accounting prospectively when it determines that the derivative is no longer effective in offsetting changes in the cash flows of a hedged item or when it is no longer probable that the forecasted transaction will occur. For the three months ended September 30, 2013 and 2012, amounts reclassified into earnings as a result of the discontinuance of cash flow hedges were immaterial.

The tables below provide the activity of accumulated OCI related to cash flow hedges for the three and nine months ended September 30, 2013 and 2012, 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
Three Months Ended September 30, 2013	**Income Statement Location**	**Energy-Related Hedges**	**Total Cash Flow Hedges**
Accumulated OCI derivative gain at June 30, 2013		$ 255(a)	$ 245
Effective portion of changes in fair value			2(b)
Reclassifications from accumulated OCI to net income	Operating Revenues	(51)	(48)
Accumulated OCI derivative gain at September 30, 2013		$ 204(a)	$ 199

(a) Excludes $11 million of losses, net of taxes, related to interest rate swaps and treasury rate locks as of September 30, 2013 and June 30, 2013.
(b) Includes $2 million of gains, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.

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

(a)

Includes $133 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, as of December 31, 2012.

(b) Includes $133 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(c) Excludes $11 million of losses and $20 million of losses, net of taxes, related to interest rate swaps and treasury locks as of September 30, 2013 and December 31, 2012, respectively.
(d) Includes $25 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended September 30, 2012	**Income Statement Location**	**Energy-Related Hedges**	**Total Cash Flow Hedges**
Accumulated OCI derivative gain at June 30, 2012		$ 923(a)(c)	$ 547
Effective portion of changes in fair value		(e)	(d)
Reclassifications from accumulated OCI to net income	Operating Revenues	(171)(b)	(88)
Accumulated OCI derivative gain at September 30, 2012		$ 752(a)(c)	$ 459

(a) Includes $232 million and $315 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd as of September 30, 2012 and June 30, 2012, respectively.
(b) Includes a $83 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c) Excludes $22 million of losses and $22 million of gains, net of taxes, related to interest rate swaps and treasury rate locks for the three months ended September 30, 2012 and June 30, 2012 respectively.
(d) Includes $0 million of losses, net of taxes, at Generation related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.
(e) Due to de-designation of all commodity cash flow positions prior to the merger date, there are no changes in fair value.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Nine Months Ended September 30, 2012	**Income Statement Location**	**Energy-Related Hedges**	**Total Cash Flow Hedges**
Accumulated OCI derivative gain at December 31, 2011		$ 925(a)(c)	$ 488
Effective portion of changes in fair value		432(e)	301(d)
Reclassifications from accumulated OCI to net income	Operating Revenues	(608)(b)	(333)
Ineffective portion recognized in income	Operating Revenues	3	3
Accumulated OCI derivative gain at September 30, 2012		$ 752(a)(c)	$ 459

(a) Includes $232 million and $420 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, as of September 30, 2012 and December 31, 2011.
(b) Includes $276 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c)

Excludes $22 million of losses and $10 million of losses, net of taxes, related to interest rate swaps and treasury rate locks for the nine months ended September 30, 2012 and year ended December 31, 2011, respectively.

(d) Includes $12 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.

(e) Includes $88 million of gains, net of taxes, related to the effective portion of changes in fair value of the five-year financial swap contract with ComEd through the date of de-designation prior to the merger.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

During the three and nine months ended September 30, 2013 and 2012, Generation s former energy related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $84 million and a $543 million pre-tax gain and $283 million and $1,005 million pre-tax gain, respectively. Given that the cash flow hedges had primarily consisted of forward power sales and power swaps and did not include power and gas options or sales, the ineffectiveness of Generation s cash flow hedges was primarily the result of differences between the locational settlement prices of the cash flow hedges and the hedged generating units. Changes in cash flow hedge ineffectiveness, were losses of $5 million for the nine months ended September 30, 2012.

Exelon s former energy-related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $84 million and $324 million pre-tax gain for the three and nine months ended September 30, 2013, respectively, and a $145 million and $548 million pre-tax gain for the three and nine months ended September 30, 2012, respectively. Changes in cash flow hedge ineffectiveness was losses of $5 million for the nine months ended September 30, 2012. Neither Exelon nor Generation will incur changes in cash flow hedge ineffectiveness in future periods as all energy-related cash flow hedge positions were de-designated prior to the merger date.

Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, and physical forward sales and purchases but for which the fair value or cash flow hedge elections were not made. For the three and nine months ended September 30, 2013 and 2012, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in operating revenues or purchased power and fuel expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in Net fair value changes related to derivatives in Exelon s and Generation s Consolidated Statements of Cash Flows. In the tables below, Change in fair value represents the change in fair value of the derivative contracts held at the reporting date. The Reclassification to realized at settlement represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Three Months Ended September 30, 2012	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Total	Intercompany Eliminations Operating Revenues(a)	Exelon Total
Change in fair value	$ (255)	$ 129	$ (126)	$ 35	$ (91)
Reclassification to realized at settlement	20	122	142	(19)	123
Net mark-to-market gains (losses)	$ (235)	$ 251	$ 16	$ 16	$ 32

Nine Months Ended September 30, 2012	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Total	Intercompany Eliminations Operating Revenues(a)	Exelon Total
Change in fair value	$ (85)	$ 121	$ 36	$ 62	$ 98
Reclassification to realized at settlement	(81)	326	245	(29)	216
Net mark-to-market gains (losses)	$ (166)	$ 447	$ 281	$ 33	$ 314

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

Proprietary Trading Activities (Exelon and Generation). For the three and nine months ended September 30, 2013 and 2012, Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) (before income taxes) relating to mark-to-market activity on derivative instruments entered into for proprietary trading purposes. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income and are included in Net fair value changes related to derivatives in Exelon s and Generation s Consolidated Statements of Cash Flows. In the tables below, Change in fair value represents the change in fair value of the derivative contracts held at the reporting date. The Reclassification to realized at settlement represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Location on Income Statement	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Change in fair value	Operating Revenue	$	$ (2)	$ 1	$ 12
Reclassification to realized at settlement	Operating Revenue	(40)	25	(36)	57
Net mark-to-market gains (losses)	Operating Revenue	$ (40)	$ 23	$ (35)	$ 69

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

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation s exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation s credit department establishes

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty s margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation s credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on Generation s credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of September 30, 2013. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, further discussed in ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $33 million, $30 million and $39 million, respectively.

Rating as of September 30, 2013	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,767	$ 191	$ 1,576	1	$ 478
Non-investment grade	16	9	7		
No external ratings					
Internally rated investment grade	472	6	466	1	238
Internally rated non-investment grade	18	1	17		
Total	$ 2,273	$ 207	$ 2,066	2	$ 716

Net Credit Exposure by Type of Counterparty	As of September 30, 2013
Investor-owned utilities, marketers and power producers	$ 743
Energy cooperatives and municipalities	916
Financial institutions	355
Other	52
Total	$ 2,066

ComEd s power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd s net credit exposure. As of September 30, 2013, ComEd s credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 5 Regulatory Matters for additional information.

PECO s supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier s performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier s lowest credit rating from the major credit rating agencies and the supplier s tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier s unsecured credit limit. As of September 30, 2013, PECO had no net credit exposure with suppliers.

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

PECO s natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO s counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of September 30, 2013, PECO had credit exposure of $9 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 5 Regulatory Matters for further information.

BGE s full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier s performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier s lowest credit rating from the major credit rating agencies and the supplier s tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier s unsecured credit limit. The seller s credit exposure is calculated each business day. As of September 30, 2013, BGE had no net credit exposure to suppliers.

BGE s regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE s recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers demands, which are not covered by the gas cost adjustment clause. At September 30, 2013, BGE had credit exposure of $1 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third party suppliers.

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

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

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

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

Credit-Risk Related Contingent Feature		**September 30, 2013**
Gross Fair Value of Derivative Contracts Containing this Feature(a)	**Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements(b)**	**Net Fair Value of Derivative Contracts Containing This Feature(c)**
$ (961)	$790	$ (171)

Credit-Risk Related Contingent Feature		**December 31, 2012**
Gross Fair Value of Derivative Contracts Containing this Feature(a)	**Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements(b)**	**Net Fair Value of Derivative Contracts Containing This Feature(c)**
$ (1,849)	$1,426	$ (423)

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

Generation had cash collateral posted of $353 million and letters of credit posted of $326 million and cash collateral held of $202 million and letters of credit held of $32 million as of September 30, 2013 and cash collateral posted of $527 million and letters of credit posted of $563 million and cash collateral held of $499 million and letters of credit held of $45 million at December 31, 2012 for counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e., to BB+ or Ba1), Generation could be required to post additional collateral of $1.8 billion as of September 30, 2013 and $2.0 billion as of December 31, 2012. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation s and Exelon s interest rate swaps contain provisions that, in the event of a merger, if Generation s debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of September 30, 2013, Generation s and Exelon s swaps were in an asset position, with a fair value of $19 million and $32 million, respectively.

See Note 21 Segment Information of the Exelon 2012 Form 10-K for further information regarding the letters of credit supporting the cash collateral.

Generation entered into SFCs with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of ComEd s standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of September 30, 2013, ComEd held immaterial amounts of collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd s annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, under the terms of ComEd s long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of September 30, 2013, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. See Note 3 Regulatory Matters of the Exelon 2012 Form 10-K for further information.

PECO s natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO s credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of September 30, 2013, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of September 30, 2013, PECO could have been required to post approximately $30 million of collateral to its counterparties.

PECO s supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

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

BGE s natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE s credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of September 30, 2013, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of September 30, 2013, BGE could have been required to post approximately $41 million of collateral to its counterparties.

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

Short-Term Borrowings

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The Registrants had the following amounts of commercial paper borrowings outstanding as of September 30, 2013 and December 31, 2012:

Commercial Paper Borrowings	**September 30, 2013**	**December 31, 2012**
Exelon Corporate	$	$
Generation		
ComEd	153	
PECO		
BGE	40	

Credit Facilities

Exelon had bank lines of credit under committed credit facilities at September 30, 2013 for short-term financial needs, as follows:

Type of Credit Facility	**Amount(a) (In billions)**	**Expiration Dates**	**Capacity Type**
Exelon Corporate			
Syndicated Revolver	$ 0.5	August 2018	Letters of credit and cash
Generation			
Syndicated Revolver	5.3	August 2018	Letters of credit and cash
Bilateral	0.3	December 2015 and March 2016	Letters of credit and cash
Bilateral	0.1	January 2015	Letters of credit
ComEd			
Syndicated Revolver	1.0	March 2018	Letters of credit and cash
PECO			
Syndicated Revolver	0.6	August 2018	Letters of credit and cash
BGE			
Syndicated Revolver	0.6	August 2018	Letters of credit and cash
Total	$ 8.4		

(a) Excludes additional credit facility agreements for Generation, ComEd, PECO and BGE with aggregate commitments of $50 million, $34 million, $34 million and $5 million, respectively, arranged with minority and community banks located primarily within ComEd s, PECO s and BGE s service territories. These facilities expire on October 18, 2014 and are solely utilized to issue letters of credit. As of September 30, 2013, letters of credit issued under these agreements for Generation, ComEd, PECO and BGE totaled $24 million, $26 million, $21 million and $1 million, respectively.

As of September 30, 2013, there were no borrowings under the Registrants credit facilities.

On January 23, 2013, Generation entered into a two year $75 million bilateral letter of credit facility with a bank. The credit agreement expires in January 2015. This facility will solely be utilized by Generation to issue letters of credit.

On March 14, 2013, ComEd extended its unsecured revolving credit facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement expires on March 28, 2018, and ComEd may request another one-year extension of that term. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any such extension or increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to extend the facility for ComEd were not material.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

On August 10, 2013, Exelon Corporate, Generation, PECO and BGE amended and extended their respective unsecured syndicated revolving credit facilities, with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively. The new covenants are substantially consistent with existing covenants. Costs incurred to amend and extend the facilities for Exelon Corporate, Generation, PECO and BGE were not material.

Effective August 10, 2013, Exelon and ComEd entered into amendments to each of their respective revolving credit facilities (the Amendments). The Amendments relate to the IRS s challenge to the position taken by Exelon on its 1999 federal income tax return with respect to the sale of ComEd s fossil generating assets in a like-kind exchange tax position. The Amendments are intended to exclude the non-cash impact of the like-kind exchange tax position from the calculation of the interest coverage ratio under each of Exelon and ComEd s respective credit facilities. See Note 12 Income Taxes for additional information.

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

On October 18, 2013, Generation, ComEd, PECO and BGE replaced their respective minority and community bank credit facility agreements in the amounts of $50 million, $34 million, $34 million and $5 million, respectively. These facilities, which expire in October 2014, are solely utilized to issue letters of credit.

Long-Term Debt

Issuance of Long-Term Debt

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

Company	Type	Interest Rate	Maturity	Amount		Use of Proceeds
Generation	Upstream Gas Lending Agreement	2.210 - 2.440%	July 22, 2016	$	5	Used to fund Upstream gas activities
Generation	DOE Project Financing	2.535 - 3.353%	January 5, 2037	$	204	Funding for Antelope Valley Solar Development
Generation	Energy Efficiency Project Financing	4.400%	August 31, 2014	$	9	Funding to install energy conservation measures in Beckley, West Virginia
Generation	Continental Wind Senior Secured Notes	6.000%	February 28, 2033	$	613	Used for general corporate purposes
ComEd	First Mortgage Bonds	4.600%	August 15, 2043	$	350	Used to repay outstanding commercial paper obligations and for general corporate purposes

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
PECO	First and Refunding Mortgage Bonds	1.200%	October 15, 2016	$ 300	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
PECO	First and Refunding Mortgage Bonds	4.800%	October 15, 2043	$ 250	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
BGE	Senior Notes	3.350%	July 1, 2023	$ 300	Used to partially refinance Notes due July 1, 2013 and for general corporate purposes

During the nine months ended September 30, 2012, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Senior Notes	4.250%	June 15, 2022	$ 523	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	Senior Notes	5.600%	June 15, 2042	$ 788	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	CEU Credit Agreement	1.990%	June 16, 2016	$ 43	Used to fund upstream gas activities
Generation	DOE Project Financing	2.330 - 3.092%	January 5, 2037	$ 100	Funding for Antelope Valley Solar Development
Generation	Clean Horizons	2.500%	June 7, 2030	$ 38	Funding for Maryland solar development
PECO	First and Refunding Mortgage Bonds	2.375%	September 15, 2022	$ 350	Used to pay at maturity First Mortgage Bonds due October 1, 2012 and for general corporate purposes
BGE	Notes	2.800%	August 15, 2032	$ 250	Used to repay total outstanding commercial paper and for general corporate purposes

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Retirement of Current and Long-Term Debt

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

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

(a) Represents debt obligations assumed by Exelon as part of the merger on March 12, 2012 that became callable at face value on June 15, 2013. Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable as of December 31, 2012 included in long-term debt to affiliate on Generation s Consolidated Balance Sheets and notes receivable from affiliates at Exelon Corporate, which are eliminated in consolidation on Exelon s Consolidated Balance Sheets. The third-party debt obligations were reported in Long-term Debt on Exelon s Consolidated Balance Sheets as of December 31, 2012. The debentures were redeemed and the intercompany loan agreements repaid on June 15, 2013.

On October 1, 2013, BGE retired $34 million aggregate principal of its 5.720% Rate Stabilization Bonds due April 1, 2017.

On October 15, 2013, PECO retired $300 million aggregate principal of its 5.600% First and Refunding Mortgage Bonds due October 15, 2013.

During the nine months ended September 30, 2012, the following long-term debt was retired:

Company	Type	Interest Rate	Maturity	Amount
ComEd	First Mortgage Bond Series 98	6.15%	March 15, 2012	$ 450
BGE	Rate Stabilization Bonds	5.68%	April 1, 2017	$ 31
BGE	Medium Term Notes	6.73 - 6.75%	June 15, 2012	$ 110
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 2
Generation	Armstrong Co. tax-exempt	5.00%	December 1, 2042	$ 46
Generation	MEDCO Tax-Exempt Bonds	Various	April 1, 2024	$ 75
Generation	Solar Revolver	2.49%	July 7, 2014	$ 13
Generation	CEU Credit Agreement	2.27%	July 16, 2016	$ 3
Exelon	Senior Notes	7.60%	April 1, 2032	$ 442
Exelon	Medium Term Notes	7.30%	June 1, 2012	$ 2

Accounts Receivable Agreement

PECO was party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its accounts receivable designated under the agreement in exchange for proceeds of $210 million, which was classified as a short-term note payable on Exelon s and PECO s Consolidated Balance Sheets as of December 31, 2012. The agreement terminated on August 30, 2013 and PECO paid down the outstanding principal of $210 million. The financial institution no longer has an undivided interest in the

accounts receivable designated under the agreement. As of December 31, 2012, the financial institution s undivided interest in Exelon s and PECO s gross accounts receivable was equivalent to $289 million, which represented the financial institution s interest in PECO s eligible receivables as calculated under the terms of the agreement. The agreement required PECO to maintain eligible receivables at least equivalent to the financial institution s undivided interest.

Willis Tower Capital Lease

In the second quarter of 2013, ComEd entered into a 20-year capital lease for transmission distribution space at Willis Tower in Chicago, Illinois. ComEd recorded $8 million on its Consolidated Balance Sheets within property plant and equipment and long-term debt at the inception of the lease. ComEd will make lease payments of less than $1 million annually in 2013-2017 and approximately $7 million thereafter.

Non-Recourse Debt

The following are descriptions of activity that occurred for the nine months ended September 30, 2013 of certain indebtedness of Exelon s project subsidiaries. The indebtedness described below is specific to certain generating facilities pledged as collateral with a net book value of approximately $1.8 billion at September 30, 2013, and all associated project financing liabilities are non-recourse to Exelon and Generation.

Continental Wind

On September 30, 2013, Continental Wind, LLC (Continental Wind), an indirect subsidiary of Exelon and Generation, completed the issuance and sale of $613 million aggregate principal amount of Continental Wind s 6.00% senior secured notes due February 28, 2033. Continental Wind owns and operates a portfolio of wind farms in Idaho, Kansas, Michigan, Oregon, New Mexico and Texas with a total net capacity of 667 MW. The net proceeds were distributed to Generation for its general business purposes. In connection with this non-recourse project financing, Exelon terminated existing interest rate swaps with a total notional amount of $350 million during the third quarter of 2013, and realized a total gain of $26 million upon termination. The gain on the interest rate swaps was recorded within OCI and will reduce the effective interest rate over the life of the debt for Exelon. See Note 10 Derivative Financial Instruments for additional information on the interest rate swaps.

In addition, Continental Wind entered into a $131 million letter of credit facility and $10 million working capital revolver facility. Continental Wind has issued letters of credit to satisfy certain of the credit support and security obligations of itself. As of September 30, 2013, the Continental Wind letter of credit facility had $90 million in letters of credit outstanding related to the project.

Antelope Valley Project Development Debt Agreement

The DOE Loan Programs Office issued a guarantee for up to $646 million for a non-recourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project is expected to be completed the first half of 2014.

In addition, Generation has issued letters of credit to support its equity investment in the project. As of September 30, 2013, Generation has reduced the letters of credit outstanding related to the project to $327 million. The letters of credit balance is expected to decline over time as scheduled equity contributions for the project are made.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

For the Three Months Ended September 30, 2012	Exelon(a)	Generation(a)	ComEd	PECO	BGE(b)
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	5.6	5.9	5.0	3.0	
Qualified nuclear decommissioning trust fund income	7.8	21.5			
Domestic production activities deduction	0.3	0.8			
Tax exempt income	(0.2)	(0.5)			
Health care reform legislation			0.6		
Amortization of investment tax credit, net deferred taxes	(4.8)	(13.0)	(0.5)	(0.3)	
Plant basis differences	(4.7)		(0.5)	(21.0)	
Production tax credits and other credits	(2.5)	(7.4)			
Fines and Penalties	(0.1)				
Other(d)	(1.2)	7.1		0.2	

Effective income tax rate	35.2%	49.4%	39.6%	16.9%	%

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

For the Nine Months Ended September 30, 2012	Exelon(a)	Generation(a)	ComEd	PECO	BGE(b)
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	(4.7)	2.5	5.4	3.2	2.3
Qualified nuclear decommissioning trust fund income	6.9	10.9			
Tax exempt income	(0.3)	(0.5)			
Health care reform legislation	0.2		0.6		(4.6)
Amortization of investment tax credit, net deferred taxes	(2.3)	(3.3)	(0.5)	(0.3)	2.9
Plant basis differences	(2.2)		(0.2)	(9.7)	7.2
Production tax credits and other credits	(2.6)	(4.3)			
Fines and Penalties	3.8	6.0			
Merger expenses (c)	3.6				(14.0)
Other	(1.3)	0.8	0.2		4.5
Effective income tax rate	36.1%	47.1%	40.5%	28.2%	33.3%

(a) Exelon activity for the three and nine months ended September 30, 2012 includes the results of Constellation and BGE for March 12, 2012 September 30, 2012. Generation activity for the three and nine months ended September 30, 2012 includes the results of Constellation for March 12, 2012 September 30, 2012.
(b) BGE activity represents the activity for the three and nine months ended September 30, 2012. BGE activity for the three months ended September 30, 2012 resulted in zero pre-tax income and zero income taxes. BGE recognized a loss before income taxes for the nine months ended September 30, 2012. As a result, positive percentages represent an income tax benefit for BGE for the nine months ended September 30, 2012.
(c) Prior to the close of the merger, the Registrants recorded the applicable taxes on merger transaction costs assuming the merger would not be completed. Upon closing of the merger, the Registrants reversed such taxes for those merger transaction costs that were determined to be non tax-deductible upon successful completion of a merger.
(d) For the three months ended September 30, 2012, Generation s effective tax rate was affected by the resolution of uncertain Federal tax positions (5.3%), the finalization of prior year tax return calculations 4.2%, changes in the forecasted activity attributable to noncontrolling interests 4.1%, and other 4.1%.

Accounting for Uncertainty in Income Taxes

Exelon, Generation, ComEd, PECO, and BGE have $2,164 million, $1,406 million, $327 million, $44 million, and $0 million, of unrecognized tax benefits as of September 30, 2013, respectively, and $1,024 million, $876 million, $67 million, $44 million, and $0 million, of unrecognized tax benefits as of December 31, 2012, respectively. The unrecognized tax benefits as of September 30, 2013 reflect an increase at Exelon and ComEd attributable to the like-kind exchange position discussed below. Furthermore, Exelon s and Generation s unrecognized tax benefits were increased by $446 million in the second quarter in anticipation of filing a refund claim with respect to legacy Constellation taxable years.

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

Settlement of Income Tax Audits

As of September 30, 2013, Exelon and Generation have approximately $160 million of federal and state unrecognized tax benefits that could significantly increase or decrease within the 12 months after the reporting date as a result of completing federal and state audits and expected statute of limitation expirations that if recognized would decrease the effective tax rate.

Nuclear Decommissioning Liabilities (Exelon and Generation)

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

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

Other Income Tax Matters

Involuntary Conversion, Like-Kind Exchange and Competitive Transition Charges

1999 Sale of Fossil Generating Assets (Exelon and ComEd). Exelon, through its ComEd subsidiary, took two positions on its 1999 income tax return to defer approximately $2.8 billion of tax gain on the sale of ComEd s fossil generating assets. Exelon deferred approximately $1.6 billion of the gain under the involuntary conversion provisions of the IRC. Exelon believed that it was economically compelled to dispose of ComEd s fossil generating plants as a result of the Illinois Act and that the proceeds from the sale of the fossil plants were properly reinvested in qualifying replacement property such that the gain could be deferred over the lives of the replacement property under the involuntary conversion provisions. The remaining approximately $1.2 billion of the gain was deferred by reinvesting the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. The IRS disagreed with both positions and asserted that the entire gain of approximately $2.8 billion was taxable in 1999.

Competitive Transition Charges (Exelon, ComEd, and PECO). Exelon contended that the Illinois Act and the Competition Act resulted in the taking of certain of ComEd s and PECO s assets used in their respective businesses of providing electricity services in their defined service areas. Exelon filed refund claims with the IRS taking the position that CTCs collected during ComEd s and PECO s transition periods represent compensation for that taking and, accordingly, were excludible from taxable income as proceeds from an involuntary conversion. The tax basis of property acquired with the funds provided by the CTCs would be reduced such that the benefits of the position are temporary in nature. The IRS disallowed the refund claims for the 1999-2001 tax years.

Status of Involuntary Conversion and CTC Positions. In the second quarter of 2010, the IRS offered to settle the disagreement over the involuntary conversion and CTC positions. Exelon concluded, based on that offer, that it had sufficient new information that a remeasurement of the involuntary conversion and CTC positions was required in accordance with applicable accounting standards. As a result of the required remeasurement, Exelon recorded $65 million (after-tax) of interest expense, of which $36 million (after-tax) and $22 million (after-tax) were recorded at ComEd and PECO, respectively. ComEd also recorded a current tax expense of $70 million offset with a tax benefit recorded at Generation of $70 million. In the third quarter of 2010, Exelon and the IRS reached a nonbinding, preliminary agreement to settle Exelon s involuntary conversion on terms consistent with the settlement offer received in the second quarter. As a result of the preliminary agreement, Exelon and ComEd eliminated any liability for unrecognized tax benefits and established a current tax payable to the IRS. Exelon paid $302 million in late 2010 in advance of the final settlement and the assessment. In November 2012, the IRS and Exelon finalized and executed definitive agreements to resolve Exelon s involuntary conversion and CTC positions.

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

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

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

In accordance with applicable accounting standards, Exelon is required to assess whether it is more-likely-than-not that it will prevail in litigation. Exelon continues to believe that its transaction is not a SILO and that it has a strong case on the merits. However, in light of the Consolidated Edison decision and Exelon s current determination that settlement is unlikely, Exelon has concluded that subsequent to December 31, 2012, it is no longer more-likely-than-not that its position will be sustained. As a result, in the first quarter of 2013 Exelon recorded a non-cash charge to earnings of approximately $265 million, which represents the amount of interest expense (after-tax) and incremental state income tax expense for periods through March 31, 2013 that would be payable in the event that Exelon is unsuccessful in litigation. Of this amount, approximately $170 million was recorded at ComEd. Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd s equity. As such, ComEd recorded on its consolidated balance sheet as of March 31, 2013, a $172 million receivable and non-cash equity contributions from Exelon. Exelon and ComEd will continue to accrue interest on the uncertain tax position, and the charges arising from future interest accruals are not expected to be material to the annual operating earnings of Exelon or ComEd. In addition, ComEd will continue to record a receivable and non-cash equity contribution from Exelon in amounts equal to the additional interest recorded by ComEd on the uncertain tax position. Exelon continues to believe that it is unlikely that the $87 million penalty assertion will ultimately be sustained and therefore no liability for the penalty has been recorded.

On September 30, 2013, the Internal Revenue Service issued a notice of deficiency to Exelon for the like-kind exchange position. Exelon will initiate litigation by December 29, 2013 in the United States Tax Court and is not required to remit any part of the asserted tax or penalty in order to litigate the issue. The litigation could take three to five years including appeals, if necessary. Decisions in the Tax Court are not controlled by the Federal Circuit s decision in Consolidated Edison.

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

As of September 30, 2013, in the event of a fully successful IRS challenge to Exelon s like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $840 million, of which approximately $305 million would be attributable to ComEd after consideration of Exelon s agreement to hold ComEd harmless, and the balance at Exelon. Litigation could take several years such that the estimated cash and interest impacts would likely change by a material amount.

Accounting for Final Tangible Property Regulations (Exelon, Generation, ComEd, PECO, and BGE)

On September 19, 2013, the Treasury Department and the IRS published final regulations regarding the tax treatment of costs incurred to acquire, produce, or improve tangible property. The Registrants are currently assessing the financial impact of this guidance and do not expect it to have a material impact. Any changes in method of accounting required to conform to the final regulations will be made for the Registrant s 2014 taxable year.

Accounting for Generation Repairs (Exelon and Generation)

On April 30, 2013, the IRS issued guidance that will facilitate the determination of the appropriate tax treatment of costs incurred to repair electric generation assets. Exelon and Generation are currently assessing its impact and expect to file a request for change in method of tax accounting for repair costs beginning with its 2014 taxable year.

13. Nuclear Decommissioning (Exelon and Generation)

Nuclear Decommissioning Asset Retirement Obligations

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

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon s and Generation s Consolidated Balance Sheets from December 31, 2012 to September 30, 2013:

Nuclear decommissioning ARO at December 31, 2012(a)	$ 4,741
Accretion expense	194
Net decrease due to changes in, and timing of, estimated cash flows	(141)
Costs incurred to decommission retired plants	(2)
Nuclear decommissioning ARO at September 30, 2013(a)	$ 4,792

(a) Includes $10 million as the current portion of the ARO at September 30, 2013 and December 31, 2012, respectively, which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

During the nine months ended September 30, 2012, Generation s ARO increased by $916 million. The increase in the ARO was largely driven by four factors: i) changes in the timing of the future nominal cash flows resulting from an assumed five year deferral to 2025 of the acceptance date of spent nuclear fuel by the DOE coupled with the fact that; ii) cash flows affected by this change in timing are re-measured and discounted at current CARFRs, which had dramatically decreased given the lower interest rate environment; iii) an increase in the estimated costs to decommission the Quad Cities and Dresden nuclear units resulting from the completion of updated decommissioning costs studies received during 2012; and iv) accretion of the obligation. The increase in the ARO due to the changes in, and timing of, estimated cash flows resulted in $10 million of expense, which is included in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income.

Nuclear Decommissioning Trust Fund Investments

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

The NDT funds associated with the former ComEd, former PECO and former AmerGen units have been funded with amounts collected from ComEd customers, PECO customers and the previous owners of the former AmerGen plants, respectively. Based on an ICC order, ComEd ceased collecting amounts from its customers to pay for decommissioning costs. PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. The most recent rate adjustment occurred on January 1, 2013, and the effective rates currently yield annual collections of approximately $24 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2018. With respect to the former AmerGen units, Generation does not collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from customers. Apart from the contributions made to the NDT funds from amounts collected from ComEd and PECO customers, Generation has not made contributions to the NDT funds.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been transferred to a third party (see Zion Station Decommissioning below). Generation has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds, on an aggregate basis for all former PECO units, compared to decommissioning obligations, as well as 5% of any additional shortfalls. The initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from ComEd customers for the former ComEd units or from the previous owners of the former AmerGen units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after all decommissioning has been completed are required to be refunded to ComEd s or PECO s customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to the former AmerGen units, Generation retains any funds remaining in the funds after decommissioning.

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

At September 30, 2013 and December 31, 2012, Exelon and Generation had NDT fund investments totaling $7,776 million and $7,248 million, respectively. The following table provides unrealized gains (losses) on NDT funds for the three and nine months ended September 30, 2013 and 2012:

		Exelon and Generation			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2013	2012	2013	2012
Net unrealized gains on decommissioning trust funds	Regulatory Agreement Units(a)	$ 103	$ 202	$ 196	$ 352
Net unrealized gains on decommissioning trust funds	Non-Regulatory Agreement Units(b)(c)	46	71	70	101

(a) Net unrealized gains related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets and Noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
(b) Excludes $9 million of net unrealized losses and $22 million of net unrealized gains related to the Zion Station pledged assets for the three months ended September 30, 2013 and 2012, respectively, and $5 million of net unrealized losses and $60 million of net unrealized gains related to the Zion Station pledged assets for the nine months ended September 30, 2013 and 2012, respectively. Net unrealized gains (losses) related to Zion Station pledged assets are included in the Payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets.
(c) Net unrealized gains related to Generation's NDT funds associated with Non-Regulatory Agreement Units are included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

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

See Note 3 Regulatory Matters and Note 22 Related Party Transactions of the Exelon 2012 Form 10-K for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning. On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. On January 7, 2013, EnergySolutions announced that it had entered a definitive acquisition agreement to be acquired by another Company. Generation reviewed the acquisition as it relates to the ASA to decommission Zion Station. Based on that review, Generation determined that the acquisition will not adversely impact decommissioning activities under the ASA. See Note 13 Asset Retirement Obligations of the Exelon 2012 Form 10-K for information regarding the specific treatment of assets, including NDT funds, and decommissioning liabilities transferred in the transaction.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

On July 14, 2011, three people filed a purported class action lawsuit in the United States District Court for the Northern District of Illinois naming ZionSolutions and Bank of New York Mellon as defendants and seeking, among other things, an accounting for use of NDT funds, an injunction against the use of NDT funds, the appointment of a trustee for the NDT funds, and the return of NDT funds to customers of ComEd to the extent legally entitled thereto. If the plaintiffs prevail on the merits of their claims, some or all of the NDT funds may no longer be available to ZionSolutions for decommissioning Zion Station, in which case, the contractual arrangement would require ZionSolutions to utilize a line of credit to complete the decommissioning. In addition, the appointment of a NDT fund trustee in this matter could impact Generation s future decommissioning activities at other stations by setting a precedent for the appointment of trustees for NDT funds. On July 20, 2012, ZionSolutions and Bank of New York Mellon filed a motion to dismiss the amended complaint for failing to state a claim. On July 29, 2013, United States District Court for the Northern District of Illinois dismissed the amended complaint. On August 26, 2013, the plaintiffs filed a notice of appeal with the United States Court of Appeals for the Seventh Circuit. The parties will submit briefs in support of their positions, following which the Court of Appeals will typically schedule oral argument.

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to pledged assets for Zion Station decommissioning within Generation s and Exelon s Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a payable to ZionSolutions in Generation s and Exelon s Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, will be recorded as a change in the payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Generation has retained its obligation to the SNF following ZionSolutions completion of its contractual obligations, to transfer the SNF at Zion Station to the DOE for ultimate disposal, and to complete all remaining decommissioning activities associated with the SNF storage facility. Generation has a liability of approximately $81 million, which is included within the nuclear decommissioning ARO at September 30, 2013. Generation also has retained NDT assets to fund its obligation to maintain and transfer the SNF at Zion Station and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payable to ZionSolutions, and withdrawals by ZionSolutions at September 30, 2013 and December 31, 2012:

	Exelon and Generation	
	September 30, 2013	**December 31, 2012**
Carrying value of Zion Station pledged assets	$ 486	$ 614
Payable to Zion Solutions(a)	443	564
Current portion of payable to Zion Solutions(b)	104	132
Withdrawals by Zion Solutions to pay decommissioning costs(c)	458	335

(a) Excludes a liability recorded within Exelon s and Generation s Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT Funds. The NDT Funds will be utilized to satisfy the tax obligations as gains and losses are realized.
(b) Included in Other current liabilities within Exelon s and Generation s Consolidated Balance Sheets.
(c) Cumulative withdrawals since September 1, 2010.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

NRC Minimum Funding Requirements. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. On April 1, 2013, Generation submitted its NRC-required biennial decommissioning funding status report as of December 31, 2012. As of December 31, 2012, Generation provided adequate funding assurance for all of its units, including Limerick Unit 1, where Generation has in place a $115 million parent guarantee to cover the NRC minimum funding assurance requirements. On October 2, 2013, the NRC issued summary findings from the NRC Staff s review of the 2013 decommissioning funding status reports for all 104 operating reactors, including the Generation operating units. Based on that review, the NRC Staff determined that Generation provided decommissioning funding assurance under the NRC regulations for all of its operating units, including Limerick Unit 1.

On January 31, 2013, Generation received a letter from the NRC indicating that the NRC has identified potential apparent violations of its regulations because of alleged inaccuracies in the Decommissioning Funding Status reports for 2005, 2006, 2007, and 2009. The NRC asserted that Generation s status reports deliberately reflected cost estimates for decommissioning its nuclear plants that were less than what the NRC says are the minimum amounts required by NRC regulations. Generation met with the NRC on April 30, 2013 for a pre-decisional enforcement conference to provide additional information to explain why Generation believes that it complied with the regulatory requirements and did not deliberately or otherwise provide incomplete or inaccurate information in its decommissioning funding status reports. While Generation does not believe that any sanction is appropriate, the ultimate outcome of this proceeding including the amount of a potential fine or sanction, if any, is uncertain. The January 31, 2013 letter from the NRC does not take issue with Generation s current funding status, and as reflected in Generation's April 1, 2013 decommissioning funding status report referenced above, Generation continues to provide adequate funding assurance for each of its units. In the normal course of NRC review, Generation has received a series of data requests that are unrelated to the potential apparent violations and the pre-decisional enforcement conference. Generation continues to cooperate with the NRC and provide the requested information. Generation does not have a definite date on which it will receive a response from the NRC. Although the government shutdown may delay receipt of a response from the NRC, Generation anticipates that the NRC will issue its findings this year.

In addition, on June 24, 2013, Exelon received a subpoena from the SEC requesting that Exelon provide the SEC with certain documents generally relating to Exelon and Generation s reporting and funding of the future decommissioning of Exelon s nuclear power plants. Exelon and Generation are cooperating with the SEC and providing the requested documents.

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

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

Defined Benefit Pension and Other Postretirement Benefits

During the first quarter of 2013, Exelon received an updated valuation of its legacy pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2013. This valuation resulted in an increase to the pension obligation of $8 million and a decrease to the other postretirement benefit obligation of $39 million. Additionally, accumulated other comprehensive loss decreased by approximately $75 million (after tax) and regulatory assets increased by approximately $93 million. During the second quarter of 2013, Exelon received the updated valuation for the legacy Constellation pension and other postretirement obligations to reflect actual census data as of January 1, 2013. This valuation resulted in an increase to the pension obligation of $23

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

million and a decrease to the other postretirement benefit obligation of $12 million. Additionally, accumulated other comprehensive loss increased by approximately $2 million (after tax) and regulatory assets increased by approximately $14 million.

The following tables present the components of Exelon s net periodic benefit costs for the three and nine months ended September 30, 2013 and 2012. The 2013 pension benefit cost for all plans is calculated using an expected long-term rate of return on plan assets of 7.50% and a discount rate of 3.92%. The 2013 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.45% for funded plans and a discount rate of 4.00% for all plans. Certain other postretirement benefit plans are not funded. A portion of the net periodic benefit cost is capitalized within the Consolidated Balance Sheets.

	Pension Benefits Three Months Ended September 30,		Other Postretirement Benefits Three Months Ended September 30,	
	2013	2012	2013	2012
Service cost	$ 79	$ 76	$ 41	$ 38
Interest cost	163	181	48	53
Expected return on assets	(253)	(258)	(33)	(28)
Amortization of:				
Transition obligation				2
Prior service cost (benefit)	3	5	(4)	(3)
Actuarial loss	140	117	20	19
Settlement charges	9	9		
Curtailment gain				(5)
Net periodic benefit cost	$ 141	$ 130	$ 72	$ 76

	Pension Benefits Nine Months Ended September 30,		Other Postretirement Benefits Nine Months Ended September 30,	
	2013	2012	2013	2012
Service cost	$ 238	$ 211	$ 122	$ 114
Interest cost	488	524	145	157
Expected return on assets	(761)	(742)	(99)	(86)
Amortization of:				
Transition obligation				8
Prior service cost (benefit)	10	12	(14)	(10)
Actuarial loss	421	338	62	58
Settlement charges	9	9		
Contractual termination benefit cost(a)		14		6
Curtailment gain				(7)
Net periodic benefit cost	$ 405	$ 366	$ 216	$ 240

(a) ComEd and BGE established regulatory assets of $1 million and $4 million, respectively, for their portion of the second quarter 2012 contractual termination benefit charge.

123

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The amounts below were included in Capital expenditures and Operating and maintenance expense during the three and nine months ended September 30, 2013 and 2012, for Generation s, ComEd s, PECO s, BGE s and BSC s allocated portion of the pension and postretirement benefit plan costs.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Pension and Other Postretirement Benefit Costs	**2013**	**2012**	**2013**	**2012**
Generation	$ 87	$ 85	$ 259	$ 259
ComEd	77	75	231	212
PECO	11	12	32	38
BGE(a)(b)	14	14	41	46
BSC(c)	24	20	58	63

(a) BGE's pension and postretirement benefit costs for the nine months ended September 30, 2012 include $12 million of costs incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012. These amounts are not included in Exelon's net periodic benefit costs for the nine months ended September 30, 2012 shown in the first table of the Defined Benefit Pension and Other Postretirement Benefits section above.

(b) BGE s pension and other postretirement benefit costs for the three and nine months ended September 30, 2012 includes a $3 million contractual termination benefit charge, which was recorded as a regulatory asset as of September 30, 2012.

(c) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO or BGE amounts above. As of September 30, 2012, ComEd and BGE each recorded a regulatory asset of $1 million related to their BSC-billed portion of the second quarter 2012 contractual termination benefit charge.

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. Exelon has contributed $255 million to its qualified pension plans in 2013, of which Generation, ComEd, PECO and BGE contributed $113 million, $115 million, $11 million and $0 million, respectively. Unlike the qualified pension plans, Exelon s non-qualified pension plans are not funded. Exelon expects to make non-qualified pension plan benefit payments of $82 million in 2013, of which Generation, ComEd, PECO, and BGE will make payments of $7 million, $1 million, $0 million, and $2 million, respectively.

Unlike qualified pension plans, other postretirement plans are not subject to statutory minimum contribution requirements. Exelon s management has historically considered several factors in determining the level of contributions to its other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued recovery). In 2013, Exelon anticipates funding its other postretirement benefit plans based on the funding considerations discussed above, with the exception of those plans previously sponsored by Constellation and AmerGen, which remain unfunded. Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $276 million in 2013, of which Generation, ComEd, PECO, and BGE expect to contribute $108 million, $112 million, $21 million, and $17 million, respectively.

Plan Assets

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

Exelon has developed and implemented a liability hedging investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans liabilities while striving to minimize the risk of significant losses. This investment strategy would tend to result in a lower expected rate of return on plan assets in future years. Trust assets for Exelon s other postretirement plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

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

Defined Contribution Savings Plans

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Savings Plan Matching Contributions	**2013**	**2012**	**2013**	**2012**
Exelon	$ 18	$ 19	$ 61	$ 55
Generation	8	9	29	25
ComEd	6	5	16	14
PECO	2	2	6	5
BGE(a)	1	1	5	5
BSC(b)	1	2	5	6

(a) BGE's matching contributions for the nine months ended September 30, 2012 include $1 million of costs incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012, which is not included in Exelon's matching contributions for the nine months ended September 30, 2012.

(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO or BGE amounts above.

15. Stock-Based Compensation Plans (Exelon, Generation, ComEd, PECO and BGE)

Exelon grants stock-based awards through its LTIP, which primarily includes stock options, restricted stock units and performance share awards. At September 30, 2013, there were approximately 16 million shares authorized for issuance under the LTIP. For the three and nine months ended September 30, 2013 and 2012, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

The Compensation Committee of Exelon s Board of Directors changed the mix of awards granted under the LTIP in 2013 by eliminating stock options in favor of the use of full value shares, consisting of performance shares and restricted stock. The performance share awards granted in 2013 will vest at the end of a three-year performance period. The performance share awards granted in 2012 and earlier had a one-year performance period and vested ratably over three years. To address the reduction in annual award opportunity resulting from the transition to a three-year performance period, the Compensation Committee also approved a one-time grant of performance share transition awards in 2013, which will vest one-third after one year, with the remaining balance vesting over a two-year performance period.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following table presents the stock-based compensation expense included in Exelon s Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Components of Stock-Based Compensation Expense	**2013**	**2012**	**2013**	**2012**
Performance share awards	$ 12	$ 5	$ 41	$ 32
Stock options	1	2	3	13
Restricted stock units	13	12	49	41
Other stock-based awards	1	1	4	3
Total stock-based compensation expense included in operating and maintenance expense	27	20	97	89
Income tax benefit	(10)	(8)	(37)	(34)
Total after-tax stock-based compensation expense	$ 17	$ 12	$ 60	$ 55

The following table presents stock-based compensation expense (pre-tax) for the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Subsidiaries	**2013**	**2012**	**2013**	**2012**
Generation	$ 10	$ 9	$ 38	$ 33
ComEd	3	2	7	9
PECO	1	1	4	4
BGE(a)	1	1	5	4
BSC(b)	12	7	43	39
Total(c)	$ 27	$ 20	$ 97	$ 89

(a) BGE's stock-based compensation expense (pre-tax) for the nine months ended September 30, 2012 excludes $2 million of cost incurred in 2012 prior to the closing of Exelon's merger with Constellation on March 12, 2012. This amount is not included in Exelon's stock-based compensation expense for the nine months ended September 30, 2012 shown in the tables titled Components of Stock-Based Compensation Expense and Subsidiaries above.

(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO and BGE amounts above.

(c) The stock-based compensation expense (pre-tax) for the three and nine months ended September 30, 2013 reflects the impact of changes to the retirement eligibility requirements for employees participating in the LTIP. In addition, the stock-based compensation expense at ComEd reflects the adoption of the ComEd Key Manager Long-Term Performance Program in 2013 for certain employees, which is not considered stock-based compensation expense under the applicable authoritative guidance. In 2012, these employees participated in the Exelon Restricted Stock Award Program.

There were no significant stock-based compensation costs capitalized during the three and nine months ended September 30, 2013 and 2012.

Stock Options

Non-qualified stock options are granted under the LTIP with exercise prices equal to the fair market value of the underlying stock at the date of grant. Generally, the stock options vest ratably over a four-year vesting period and expire ten years from the date of grant.

There were no stock options granted in 2013. The Compensation Committee eliminated stock option grants by changing the mix of long-term incentives for senior vice presidents (SVPs) and higher officers from 75% performance shares and 25% stock options to 67% performance shares and 33% restricted stock units (RSUs).

At September 30, 2013, $3 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of 1.8 years.

Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost of services is measured based on the grant date fair value of the restricted stock unit issued. The requisite service period for restricted stock units is generally three to five years. However, certain restricted stock unit awards become fully vested upon the employee reaching retirement-eligibility.

At September 30, 2013 and December 31, 2012, Exelon had obligations related to outstanding restricted stock units not yet settled of $67 million and $58 million, respectively, which are included in common stock in Exelon s Consolidated Balance Sheets. As of September 30, 2013 and December 31, 2012, Exelon had no obligations related to outstanding restricted stock units that will be settled in cash. During the three months ended September 30, 2013 and 2012, Exelon settled restricted stock units with a fair value totaling $3 million and $4 million, respectively. During the nine months ended September 30, 2013 and 2012, Exelon settled restricted stock units with a fair value totaling $26 million and $23 million, respectively. At September 30, 2013, $69 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.2 years.

Performance Share and Performance Share Transition Awards

Performance share awards are granted under the LTIP with the 2013 performance share awards being settled 50% in common stock and 50% in cash at the end of the three-year performance period except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain ownership requirements are satisfied. The 2012 performance share awards are being settled 50% in common stock and 50% in cash over the three-year vesting term with executive vice presidents and higher officers receiving 100% cash if certain ownership requirements are satisfied. The performance shares granted prior to 2012 generally vest and settle over a three-year period with the holders receiving shares of common stock and/or cash annually during the vesting period.

The one-time 2013 performance share transition awards, which provide an opportunity to earn an award contingent on company performance, will be settled 50% in common stock and 50% in cash, except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain ownership requirements are satisfied. One-third of the award vests and is payable after a one-year performance period while the remaining two-thirds vests and is payable after a two-year performance period.

The payout of the 2013 performance share awards and one-time performance share transition awards are based on the Company s performance against specific operational and financial goals set annually during the respective performance periods. As a result, the 2013 performance share awards have been divided into equal tranches for the purpose of expense recognition as though the respective award were multiple awards; with each tranche representing a corresponding fiscal year. The one-time performance share transition awards have also been divided into multiple tranches for the purpose of expense recognition. One tranche reflects the one-third of the awards that vests and are payable after a one-year period. The two-thirds of the one-time performance share transition awards that are subject to a two-year performance period have also been divided into equal tranches; with each tranche representing a corresponding fiscal year. The grant date for each tranche of the 2013 performance share and one-time performance share transition awards is the date in which the performance goals for that fiscal year are approved and communicated, which typically occurs at the corresponding January Compensation Committee meeting.

The 2013 performance share awards and one-time performance share transition awards are recorded at fair value at the grant dates for each tranche, with the estimated grant date fair value based on the expected payout of the award, which may range from 50% to 150% of the payout target. The 2013 performance share awards also include a total shareholder return modifier (TSR) that may increase or decrease the award up to 25% and an individual performance modifier (IPM) that can decrease the award by up to 50% or increase the award by up to 10% for senior vice presidents and higher officers or up to 20% for vice presidents. The one-time performance share transition award is not affected by either TSR or the IPM.

The common stock portion of the performance share and one-time performance share transition awards is considered an equity award being valued based on Exelon s stock price on the grant date. The cash portion of the awards is considered a liability award which is remeasured each reporting period based on Exelon s current stock price. As the value of the common stock and cash portions of the awards are based on Exelon s stock price during the performance period, coupled with changes in the total shareholder return modifier and expected payout of the award, the compensation costs are subject to volatility until payout is established.

The 2012 performance share awards are recorded at fair value at the date of grant with the estimated grant date fair value based on the expected payout of the award, which may range from 75% to 125% of the payout target. The common stock portion is considered an equity award with the 75% payout floor being valued based on Exelon s stock price on the grant date. The cash portion of the award is considered a liability award with the 75% payout floor being remeasured each reporting period based on Exelon s current stock price. The expected payout in excess of the 75% floor for the equity and liability portions are remeasured each reporting period based on Exelon s current stock price and changes in the expected payout of the award; therefore these portions of the award are subject to volatility until the payout is established.

For nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method. For performance share and one-time performance share transition awards granted to retirement-eligible employees, the value of the performance shares in recognized ratably over the vesting period, which is the year of grant.

At September 30, 2013 and December 31, 2012, Exelon had obligations related to outstanding performance shares not yet settled of $63 million and $53 million, respectively. During the three months ended September 30, 2013 and 2012, Exelon settled performance shares with a fair value totaling $3 million and $3 million, respectively, of which $3 million and $0 million was paid in cash, respectively. During the nine months ended September 30, 2013 and 2012, Exelon settled performance shares with a fair value totaling $25 million and $22 million, respectively, of which $12 million and $3 million was paid in cash, respectively. As of September 30, 2013, $32 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 2.3 years. In addition, as of September 30, 2013, $19 million of total unrecognized compensation costs related to nonvested one-time performance share transition awards are expected to be recognized over the remaining weighted-average period of 1.3 years.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

The following table presents changes in accumulated other comprehensive income (loss) (AOCI) by component for nine months ended September 30, 2013:

	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon(a)						
Beginning balance	$ 368	$	$ (3,137)	$	$ 2	$ (2,767)
OCI before reclassifications	25	(1)	73	(5)	46	138
Amounts reclassified from AOCI(b)	(194)		157		5	(32)
Net current-period OCI	(169)	(1)	230	(5)	51	106
Ending balance	$ 199	$ (1)	$ (2,907)	$ (5)	$ 53	$ (2,661)
Generation(a)						
Beginning balance	$ 512	$	$	$	$ 1	$ 513
OCI before reclassifications	12	(1)		(5)	47	53
Amounts reclassified from AOCI(b)	(328)				5	(323)
Net current-period OCI	(316)	(1)		(5)	52	(270)
Ending balance	$ 196	$ (1)	$	$ (5)	$ 53	$ 243
PECO(a)						
Beginning balance	$	$ 1	$	$	$	$ 1
OCI before reclassifications						
Amounts reclassified from AOCI(b)						
Net current-period OCI						
Ending balance	$	$ 1	$	$	$	$ 1

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in accumulated other comprehensive income.

(b) See next table for details about these reclassifications.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Three Months Ended September 30, 2013

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2013

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

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in net income.
(b) This accumulated other comprehensive income component is included in the computation of net periodic pension and OPEB cost (see note 14 for additional details).
(c) Amortization of deferred compensation unit is allocated to capital and operating and maintenance expense.

The following table presents income tax expense (benefit) allocated to each component of other comprehensive income (loss) during the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Exelon				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	$	$ 1	$	$ 2
Actuarial loss reclassified to periodic cost	33	28	97	82
Transition obligation reclassified to periodic cost		1		2
Pension and non-pension postretirement benefit plans valuation adjustment	(6)	(43)	44	(51)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	**2012**	**2013**	**2012**
Deferred compensation unit valuation adjustment			6	
Change in unrealized loss on cash flow hedges	(35)	(57)	(109)	36
Change in unrealized income on equity investments	9	11	32	15
Change in unrealized loss on marketable securities				1
Total	$ 1	$ (59)	$ 70	$ 87
Generation				
Change in unrealized loss on cash flow hedges	$ (36)	$ (113)	$ (209)	$ (122)
Change in unrealized income on equity investments	9	11	32	15
Total	$ (27)	$ (102)	$ (177)	$ (107)

17. Earnings Per Share and Equity (Exelon and PECO)

Earnings per Share (Exelon)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	**2012**	**2013**	**2012**
Net income attributable to common shareholders	$ 738	$ 296	$ 1,224	$ 782
Average common shares outstanding basic	857	854	856	804
Assumed exercise of stock options, performance share awards and restricted stock	3	3	4	2
Average common shares outstanding diluted	860	857	860	806

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 20 million for the three and nine months ended September 30, 2013 and 18 million and 13 million for the three and nine months ended September 30, 2012, respectively.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion as of September 30, 2013. In 2008, Exelon management decided to defer indefinitely any share repurchases.

Preferred Securities Redemption (Exelon and PECO)

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

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

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

The following is an update to the current status of commitments and contingencies set forth in Note 19 of the Exelon 2012 Form 10-K.

Commitments

Energy Commitments

As of September 30, 2013, Generation s commitments relating to purchases from unaffiliated utilities and others of energy, capacity and transmission rights, are as indicated in the following table:

	Net Capacity Purchases(a)	REC Purchases(b)	Transmission Rights Purchases(c)	Purchased Energy from CENG	Total
2013	$ 86	$ 17	$ 7	$ 186	$ 296
2014	396	124	26	745	1,291
2015	368	97	13		478
2016	285	57	2		344
2017	223	16	2		241
Thereafter	526	5	34		565
Total	$ 1,884	$ 316	$ 84	$ 931	$ 3,215

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at September 30, 2013, net of fixed capacity payments expected to be received by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. These capacity payments represent the fixed, or pre-determined, payment for output from contracted generation facilities. Output in this context generally includes products such as energy, capacity, and various ancillary services associated with generating facilities. Expected payments include certain capacity charges which are contingent on plant availability.

(b) Power-related purchases include firm REC purchase agreements. The table excludes renewable energy purchases that are contingent in nature.

(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

In connection with Constellation s comprehensive agreement with EDF in October 2010, Constellation s and EDF s existing power purchase agreements with CENG were modified to be unit-contingent through the end of their original term in 2014. Under these agreements, CENG has the ability to fix the energy price on a forward basis by entering into monthly energy hedge transactions for a portion of the future sale, while any unhedged portions will be provided at market prices by default. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, Generation agreed to purchase 50.01% of the available output of CENG s nuclear plants at market prices. Generation discloses in the table above commitments to purchase from CENG at fixed prices. All commitments to purchase at market prices, which include all purchases subsequent to December 31, 2014, are excluded from the table. Generation continues to own a 50.01% membership interest in CENG that is accounted for as an equity method investment. See Note 6 Investment in Constellation Energy Nuclear Group, LLC for more details on this arrangement.

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

ComEd s, PECO s and BGE s electric supply procurement, curtailment services, REC and AEC purchase commitments as of September 30, 2013 are as follows:

		Expiration within					
	Total	**2013**	**2014**	**2015**	**2016**	**2017**	**2018 and beyond**
ComEd							
Electric supply procurement(a)	$ 878	$ 142	$ 323	$ 136	$ 137	$ 140	$
Renewable energy and RECs(b)	1,604	20	67	74	76	77	1,290
PECO							
Electric supply procurement(c)	886	211	584	91			
AECs	15	1	2	2	2	2	6
BGE							
Electric supply procurement(d)	1,122	227	669	226			
Curtailment services(e)	147	13	46	41	34	13	

(a) ComEd entered into various contracts for the procurement of electricity that started to expire in 2012, and will continue to expire through 2017. ComEd is permitted to recover its electric supply procurement costs from retail customers with no mark-up. See Note 5 Regulatory Matters for additional information.
(b) ComEd entered into 20-year contracts for renewable energy and RECs beginning June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. 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 in the first quarter of 2013. See Note 5 Regulatory Matters for additional information.
(c) PECO entered into various contracts for the procurement of electric supply to serve its default service customers that expire between 2013 and 2015. PECO is permitted to recover its electric supply procurement costs from default service customers with no mark-up in accordance with its PAPUC-approved DSP Programs. See Note 5 Regulatory Matters for additional information.
(d) BGE entered into various contracts for the procurement of electricity that expire between 2013 and 2015. The cost of power under these contracts is recoverable under MDPSC approved fuel clauses. See Note 5 Regulatory Matters for additional information.
(e) BGE has entered into various contracts with curtailment services providers related to transactions in PJM's capacity market. See Note 5 Regulatory Matters for additional information.

Fuel Purchase Obligations

In addition to the energy commitments described above, Generation has commitments to purchase fuel supplies for nuclear and fossil generation (and with respect to coal, commitments to sell coal). PECO and BGE have commitments to purchase natural gas, related to transportation, storage capacity and services to serve customers in their gas distribution service territory. As of September 30, 2013, these net commitments were as follows:

		Expiration within					
	Total	**2013**	**2014**	**2015**	**2016**	**2017**	**2018 and beyond**
Generation	$ 7,901	$ 339	$ 1,199	$ 1,233	$ 1,021	$ 1,050	$ 3,059
PECO	477	54	128	100	78	36	81
BGE	603	46	123	52	51	50	281

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Other Purchase Obligations

The Registrants other purchase obligations as of September 30, 2013, which primarily represent commitments for services, materials and information technology, are as follows:

		Expiration within					
	Total	**2013**	**2014**	**2015**	**2016**	**2017**	**2018 and beyond**
Exelon	$ 269	$ 33	$ 38	$ 32	$ 31	$ 31	$ 104
Generation	628	133	178	127	40	38	112
ComEd(a)	82	7	41	5	5	5	19
PECO(a)	54	19	25	1	1	1	7
BGE(a)	25	2	21	2			

(a) Purchase obligations include commitments related to smart meter installation. See Note 5 Regulatory Matters for additional information.

Construction Commitments

Generation has committed to the construction of a solar PV facility in Los Angeles County, California. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013 and an expectation of full commercial operation in the first half of 2014. Generation's estimated remaining commitment for the project is $180 million.

On July 3, 2013, Generation executed a Turbine Supply Agreement to expand its Beebe wind project in Michigan. The estimated remaining commitment under the contract is $52 million and achievement of commercial operations is expected in 2014.

On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland generation site with 120MW of new natural gas-fired generation to satisfy certain merger commitments. The estimated remaining commitment under the contract is $80 million and achievement of commercial operation is expected in 2015. See Note 4 Mergers and Acquisitions for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the merger.

Refer to Note 3 Regulatory Matters of the Exelon 2012 Form 10-K for information on investment programs associated with regulatory mandates, such as ComEd s Infrastructure Investment Plan under EIMA, PECO s Smart Meter Procurement and Installation Plan and BGE s comprehensive smart grid initiative.

Constellation Merger Commitments

In December 2011, Exelon and Constellation reached a settlement with the State of Maryland and the City of Baltimore and other interested parties in connection with the regulatory proceedings related to the merger that was pending before the MDPSC. As part of this settlement and the application for approval of the merger by MDPSC, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of more than $1 billion.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

On February 17, 2012, the MDPSC approved the merger with conditions. Many of the conditions were reflective of the settlement agreements described above. The following costs were recognized after the closing of the merger and are included in Exelon s, Generation s and BGE s Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2012. See Note 4 Merger and Acquisitions of the Exelon 2012 Form 10-K for additional information on the merger.

Description	Payment Period	BGE	Generation	Exelon	Statement of Operations Location
BGE rate credit of $100 per residential customer(a)	Q2 2012	$ 113	$	$ 113	Revenues
Customer investment fund to invest in energy efficiency and low-income energy assistance to BGE customers	2012 to 2014			113.5	O&M Expense
Contribution for renewable energy, energy efficiency or related projects in Baltimore	2012 to 2014			2	O&M Expense
Charitable contributions at $7 million per year for 10 years	2012 to 2021	28	35	70	O&M Expense
State funding for offshore wind development projects	Q2 2012			32	O&M Expense
Miscellaneous tax benefits	Q2 2012	(2)		(2)	Taxes Other Than Income
Total		$ 139	$ 35	$ 328.5	

(a) Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

Contingencies

Commercial Commitments

The Registrants commercial commitments as of September 30, 2013, representing commitments potentially triggered by future events were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Letters of credit (non-debt)(a)	$ 1,514	$ 1,463	$ 26	$ 22	$ 1
Guarantees	4,908(b)	1,271(c)	209(d)	181(e)	252(f)
Nuclear insurance premiums(g)	3,096	3,096			
Total commercial commitments	$ 9,518	$ 5,830	$ 235	$ 203	$ 253

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

(b) Primarily reflects parental guarantees issued on behalf of Generation to allow the flexibility needed to conduct business with counterparties without having to post other forms of collateral. Also reflects guarantees issued to ensure performance under specific contracts, preferred securities of financing trusts, property leases, indemnifications, NRC minimum funding assurance requirements and $211 million on behalf of CENG nuclear generating facilities for credit support and miscellaneous guarantees. The estimated net exposure for obligations under commercial transactions covered by these guarantees was $0.6 billion at September 30, 2013, which represents the total amount Exelon could be required to fund based on September 30, 2013 market prices.

(c) Primarily reflects guarantees issued to ensure performance under energy marketing and other specific contracts and $211 million on behalf of CENG nuclear generating facilities for credit support. The estimated net exposure for obligations under commercial transactions covered by these guarantees was $0.2 billion at September 30, 2013, which represents the total amount Generation could be required to fund based on September 30, 2013 market prices.

(d) Primarily reflects full and unconditional guarantees of $200 million Trust Preferred Securities of ComEd Financing III, which is a 100% owned finance subsidiary of ComEd.

(e) Primarily reflects full and unconditional guarantees of $178 million Trust Preferred Securities of PECO Trust III and IV, which are 100% owned finance subsidiaries of PECO.

(f) Primarily reflects full and unconditional guarantees of $250 million Trust Preferred Securities of BGE Capital Trust II, which is a 100% owned finance subsidiary of BGE.

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

Nuclear Insurance (Exelon and Generation)

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and also to limit the liability of nuclear reactor owners for such claims from any single incident. As of September 30, 2013, the current liability limit per incident was $13.6 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. An inflation adjustment must be made at least once every 5 years and the last inflation adjustment was made effective September 10, 2013. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. As of September 30, 2013, the amount of nuclear energy liability insurance purchased is $375 million for each operating site. Additionally, the Price-Anderson Act requires a second layer of protection through the mandatory participation in a retrospective rating plan for power reactors (currently 104 reactors) resulting in an additional $13.2 billion in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Under the Price-Anderson Act, the maximum assessment in the event of an incident for each nuclear operator, per reactor, per incident (including a 5% surcharge), is $127.3 million, payable at no more than $19 million per reactor per incident per year. Exelon s maximum liability per incident is approximately $2.8 billion. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.6 billion limit for a single incident.

Additionally, Generation is also required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member. Premiums paid to NEIL by its members are subject to assessment for adverse loss experience (the retrospective premium obligation). The maximum combined retrospective premium amount that Generation could be required to pay due to participation in the Price-Anderson Act retrospective rating plan for power reactors and the NEIL retrospective premium obligation is $3.1 billion, which is included above in the Commercial Commitments table. See the Nuclear Insurance section within Note 19 Commitments and Contingencies of the Exelon 2012 Form 10-K for additional details on Generation s nuclear insurance premiums.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Indemnifications Related to Sale of Sithe (Exelon and Generation)

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

The estimated maximum possible exposure to Exelon related to the guarantees provided as part of the sales transaction to Dynegy was approximately $200 million at September 30, 2013. Generation believes that it is remote that it will be required to make any additional payments under the guarantee, and currently has no recorded liabilities associated with this guarantee. Generation expects that the exposure covered by this guarantee will expire in 2014. The guarantee is included above in the Commercial Commitments table under guarantees.

Indemnifications Related to Sale of TEG and TEP (Exelon and Generation)

On February 9, 2007, Tamuin International Inc. (TII), a wholly owned subsidiary of Generation, sold its 49.5% ownership interests in TEG and TEP to a subsidiary of AES Corporation for $95 million in cash plus certain purchase price adjustments. In connection with the transaction, Generation entered into a guarantee agreement under which Generation guaranteed the timely payment of TII s obligations to the subsidiary of AES Corporation pursuant to the terms of the purchase and sale agreement relating to the sale of TII s ownership interests. Generation was required to perform in the event that TII did not pay any obligation covered by the guarantee that was not otherwise subject to a dispute resolution process. Portions of the exposures covered by this guarantee expired in 2008, and the remaining guarantee expired in the third quarter of 2013. Generation was not required to make payments under the guarantee, and therefore, has no further obligation related to this guarantee as of September 30, 2013.

Environmental Issues

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

ComEd, PECO and BGE have identified sites where former MGP activities have or may have resulted in actual site contamination. For almost all of these sites, ComEd, PECO or BGE is one of several PRPs that may be responsible for ultimate remediation of each location.

ComEd has identified 42 sites, 16 of which have been approved for cleanup by the Illinois EPA or the U.S. EPA and 26 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2016.

PECO has identified 26 sites, 16 of which have been approved for cleanup by the PA DEP and 10 that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2020.

BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor s acquisition. Two gas manufacturing sites require some level of

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

remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. One gas purification site is in the initial stages of investigation at the direction of the MDE.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. BGE is authorized to and is currently recovering environmental costs for the remediation of former MGP facility sites from customers; however, while BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. ComEd, PECO and BGE have recorded regulatory assets for the recovery of these costs. During the third quarter of 2013, ComEd and PECO completed an annual study of their future estimated MGP remediation requirements. The results of these studies indicated that additional remediation would be required at certain sites; accordingly, ComEd and PECO increased their reserves and regulatory assets by less than $1 million and $6 million, respectively. See Note 5 Regulatory Matters for additional information regarding the associated regulatory assets.

As of September 30, 2013 and December 31, 2012, the Registrants had accrued the following undiscounted amounts for environmental liabilities in other current liabilities and other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

September 30, 2013	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 345	$ 280
Generation	56	
ComEd	237	232
PECO	51	48
BGE	1	

December 31, 2012	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 351	$ 298
Generation	42	
ComEd	261	254
PECO	47	44
BGE	1	

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

Water Quality

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

On March 28, 2011, the U.S. EPA issued the proposed regulation under Section 316(b). The proposal does not require closed-cycle cooling (e.g., cooling towers) as the best technology available to address impingement and entrainment. The proposal provides the state permitting agency with discretion to determine the best technology available to limit entrainment (drawing aquatic life into the plants cooling system) mortality, including application of a cost-benefit test and the consideration of a number of site-specific factors. After consideration of these factors, the state permitting agency may require closed cycle cooling, an alternate technology, or determine that the current technology is the best available. The proposed rule also imposes limits on impingement (trapping aquatic life on screens) mortality, which likely will be accomplished by the installation of screens or another technology at the intake. Exelon filed comments on the proposed regulation on August 18, 2011, stating its support for a number of its provisions (e.g., cooling towers not required as best technology available, and the use of site-specific and cost benefit analysis) while also noting a number of technical provisions that require revision to take into account existing unit operations and practices within the industry.

In June 2012, the U.S. EPA published two Notices of Data Availability (NODA) seeking public comment on alternate compliance technologies for impingement and the use of a public opinion survey to calculate the so-called non-use benefits of the rule. Exelon filed comments for each NODA, supporting the additional flexibility afforded by the impingement NODA, and opposing the NODA relating to calculation of non-use benefits due to its inaccurate and unreliable methodologies that would artificially inflate the benefits of proposed technologies that would otherwise not be cost-effective. On June 27, 2013, the U.S. EPA agreed to amend the court approved Settlement Agreement to extend the deadline to issue a final rule until November 4, 2013; on October 30, 2013 the Agency invoked the *force majeure* provision of the Settlement Agreement to extend the final rule deadline until November 20, 2013 due to the early October 2013 federal government shutdown. Until the rule is finalized, the state permitting agencies will continue to apply their best professional judgment to address impingement and entrainment.

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

It is unknown at this time whether the NJDEP permit programs will require closed-cycle cooling at Salem. In addition, the economic viability of Generation s other power generation facilities, as well as CENG s, without closed-cycle cooling water systems will be called into question by any requirement to construct cooling towers. Should the final rule not require the installation of cooling towers, and retain the flexibility afforded the state permitting agencies in applying a cost benefit test and to consider site-specific factors, the impact of the rule would be minimized even though the costs of compliance could be material to Generation and CENG.

Given the uncertainties associated with the requirements that will be contained in the final rule, Generation cannot predict the eventual outcome or estimate the effect that compliance with any resulting Section 316(b) or interim state requirements will have on the operation of its and CENG's generating facilities and its future results of operations, cash flows and financial position.

Groundwater Contamination. In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third-party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a $1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. Prior to the Merger, Constellation recorded in its Consolidated Balance Sheets total liabilities of approximately $30 million to comply with the consent decree with an additional $3 million recognized through purchase accounting. During the three months ended September 30, 2013, Generation increased its reserve by $2 million based on an update of future estimated remediation costs. The remaining liability as of September 30, 2013, is approximately $15 million. In addition, a private party has asserted claims relating to groundwater contamination. Generation believes that these claims are without merit and is vigorously contesting them. As of September 30, 2013, Generation believes that it is remote that it will be required to make payments under these private party claims.

Air Quality

Cross State Air Pollution Rule (CSAPR). On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) vacated the CAIR, which had been promulgated by the U.S. EPA to reduce power plant emissions of SO_2 and NO_x. The D.C. Circuit Court later remanded the CAIR to the U.S. EPA, without invalidating the entire rulemaking, so that the U.S. EPA could correct CAIR in accordance with the D.C. Circuit Court s July 11, 2008 opinion. On July 7, 2011, the U.S. EPA published the final rule, known as the CSAPR. The CSAPR requires 28 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states.

Numerous entities challenged the CSAPR in the D.C. Circuit Court, and some requested a stay of the rule pending the Court s consideration of the matter on the merits. On December 30, 2011, the Court granted a stay of the CSAPR, and directed the U.S. EPA to continue the administration of CAIR in the interim. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA has exceeded its authority in certain material aspects of the CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. On January 24, 2013, the Court denied petitions for reconsideration of the ruling by the three-judge panel. In June 2013, the U.S. Supreme Court granted the U.S. EPA s petition to review the D.C. Circuit Court s CSAPR decision. Oral argument has been scheduled for December 10, 2013.

Under the CSAPR, generation units were to receive allowances based on historic heat input and intrastate, and limited interstate, trading of allowances was permitted. The CSAPR restricted entirely the use of pre-2012 allowances. Existing SO_2 allowances under the ARP would remain available for use under ARP. As of September 30, 2013, Generation had $64 million of emission allowances carried at the lower of weighted average cost or market.

EPA Mercury and Air Toxics Standards (MATS). The MATS rule became final on April 16, 2012. The MATS rule reduces emissions of toxic air pollutants, and finalized the new source performance standards for fossil fuel-fired electric utility steam generating units (EGUs). The MATS rule requires coal-fired EGUs to achieve high removal rates of mercury, acid gases and other metals from air emissions. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that smaller, older, uncontrolled coal units will retire rather than make these investments. Coal units with existing controls that do not meet the required standards may need to upgrade existing controls or add new controls to comply. In addition, the new standards will require oil units to achieve high removal rates of metals. Owners of oil units not currently meeting the proposed emission standards

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

may choose to convert the units to light oils or natural gas, install control technologies or retire the units. The MATS rule requires generating stations to meet the new standards three years after the rule takes effect, April 16, 2015, with specific guidelines for an additional one or two years in limited cases. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon was granted permission by the Court to intervene in support of the rule. A decision by the Court will not occur until 2014. The outcome of the appeal, and its impact on power plant operators investment and retirement decisions, is uncertain.

Exelon, along with the other co-owners of Conemaugh Generating Station are moving forward with plans to improve the existing scrubbers and install Selective Catalytic Reduction (SCR) controls to meet the mercury removal requirements of MATS.

In addition, as of September 30, 2013, Exelon had a $691 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases extending through 2028-2032. While Exelon currently estimates the value of these plants at the end of the lease term will be in excess of the recorded residual lease values, after the impairment recorded in the second quarter of 2013, final applications of the CSAPR and MATS regulations could negatively impact the end-of-lease term values of these assets, which could result in a future impairment loss that could be material. See Note 7 Impairment of Long-Lived Assets for additional information.

National Ambient Air Quality Standards (NAAQS). The U.S. EPA previously announced that it would complete a review of all NAAQS by 2014. Oral argument in the litigation (*State of Miss. v. EPA*) of the final 2008 ozone standard occurred in the D.C. Circuit Court in November 2012 and a final Court decision was issued on July 23, 2013 with the 2008 primary ozone standard upheld, but the secondary standard remanded to EPA for reconsideration. Concurrent with litigation of the 2008 ozone standard, the U.S. EPA continues its regular, periodic review of the ozone NAAQS and is expected to propose revisions in the fall of 2014, with preliminary indications that the U.S. EPA will likely propose a tightened standard. It is unclear at this point in time whether the U.S. EPA will be able to respond to the Court remand of the secondary 2008 ozone standard on a timeframe that would be any quicker than that of the U.S. EPA s current, periodic review schedule. In December 2012, the U.S. EPA issued its final revisions to the Agency s particulate matter (PM) NAAQS. In its final rule, the U.S. EPA lowered the annual PM2.5 standard, but declined to issue a new secondary NAAQS to improve urban visibility. The U.S. EPA indicated in its final rule that by 2020 it expects most areas of the country will be in attainment of the new PM2.5 NAAQS based on currently expected regulations, such as the MATS regulation. It is unclear if the vacatur of the CSAPR, one of the regulations that the U.S. EPA is relying on to assist with future PM reduction, would alter the U.S. EPA s view since either CAIR or a finalized CSAPR regulation would be in effect leading up to 2020. In March 2013, a number of industry coalitions filed a joint lawsuit challenging the new PM2.5 standard. Also during early 2013, the D.C. Circuit remanded several rules for implementation of earlier PM2.5 NAAQS to the U.S. EPA for revision of certain aspects of the rules, with a requirement that the U.S. EPA re-promulgate regulations in conformance with the correct subparts of the Clean Air Act.

In addition to these NAAQS, the U.S. EPA also finalized nonattainment designations for certain areas in the United States for the 2010 one-hour SO_2 standard on August 5, 2013, and indicated that additional nonattainment areas will be designated in a future rulemaking. EPA will require states to submit state implementation plans (SIPs) for nonattainment areas by April 2015. With regard to Texas and Maryland, no nonattainment areas were identified in EPA s final designation rule. With regard to Illinois and Pennsylvania, several counties, or portions of counties, in each state were identified as nonattainment. The U.S. EPA will follow the approach outlined in a February 2013 EPA strategy document that establishes a process and timeline for the Agency to address additional designations in states counties under a future rulemaking. Nonattainment county compliance with the one-hour SO_2 standard is required by October 2018. While significant SO2 reductions will occur as a result of MATS compliance in 2015, Exelon is unable to predict the requirements of pending states SIPs to further reduce SO_2 emissions in support of attainment of the one hour SO_2 standard.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

On August 6, 2007, ComEd received a NOV addressed to it and Midwest Generation from the U.S. EPA, alleging, in relevant part, that ComEd and Midwest Generation violated and are continuing to violate provisions of the Clean Air Act as a result of the modification and/or operation of six electric generation stations located in northern Illinois that have been owned and operated by Midwest Generation since their purchase from ComEd in 1999. In August 2009, the United States and the State of Illinois filed a complaint against Midwest Generation with the U.S. District Court for the Northern District of Illinois initiating enforcement proceedings with respect to most of the alleged Clean Air Act violations set forth in the NOV. Neither ComEd nor Exelon was named as a defendant in this original complaint. In March 2010, the District Court granted Midwest Generation s partial motion to dismiss all but one of the claims against Midwest Generation. The District Court held that Midwest Generation cannot be liable for any alleged violations relating to construction that occurred prior to Midwest Generation s ownership of the stations. In May 2010, the government plaintiffs filed an amended complaint against Midwest Generation asserting claims substantially similar to those in the original complaint, and added ComEd and EME as defendants. The amended complaint seeks injunctive relief and civil penalties against all defendants, although not all of the claims specifically pertain to ComEd. On March 16, 2011, the District Court granted ComEd s motion to dismiss the May 2010 complaint in its entirety as it relates to ComEd. On January 3, 2012, upon leave of the District Court, the government parties appealed the dismissal of ComEd to the U.S. Circuit Court of Appeals for the Seventh Circuit. On July 8, 2013, the Circuit Court affirmed the District Court s dismissal of the complaint against ComEd. On September 19, 2013, the Circuit Court denied the petition for a rehearing filed by the governmental parties. Exelon, Generation and ComEd have concluded that, in light of the Circuit Court decision, the likelihood of loss is remote. Therefore, no reserve has been established.

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

The Bankruptcy Court approved the rejection of a coal rail car lease under which Midwest Generation had agreed to reimburse ComEd for all obligations. The rejection left Generation as the party responsible to make remaining payments under the lease. In January 2013, Generation made the final $10 million payment due under the lease agreement which had been reserved for at December 31, 2012. As a result of the bankruptcy filing, Exelon and Generation have recorded liabilities as of September 30, 2013 of $3 million for estimated payments for asbestos personal injury claims filed pre-Petition Date. Exelon and Generation currently expect Midwest Generation or its successor will remain responsible for asbestos personal injury claims filed post-Petition Date, and as such have recorded no liability for such amounts. Requirements for Generation to ultimately satisfy such claims could have a material adverse impact on Exelon s and Generation s future results of operations. During the second quarter of 2013, ComEd filed proofs of claim of $21 million with the Bankruptcy Court for amounts owed by EME and Midwest Generation for the coal rail car lease, ComEd utility payments and certain legal costs. As of September 30, 2013, Exelon and ComEd have not recorded a receivable for the filed proofs of claim because recovery of such amount cannot be assured at this point in the bankruptcy. Exelon and ComEd will not record financial benefits associated with claim recoveries until realized.

As of the Petition Date, Generation had wholesale power transactions with Edison Mission Marketing and Trading, an affiliate of Midwest Generation not included in the bankruptcy proceeding. Generation expects these transactions to be fully settled in the normal course.

Certain environmental laws and regulations subject current and prior owners of properties or generators of hazardous substances at such properties to liability for remediation costs of environmental contamination. As a prior owner of the generating stations, ComEd (and Generation, through its agreement in the 2001 restructuring to assume ComEd s rights and obligations associated with its former generation business) could face liability (along with any other potentially responsible parties) for environmental conditions requiring remediation, with the determination of the allocation among the parties subject to many uncertain factors, including the impact of Midwest Generation s bankruptcy. Additionally, the obligations of EME and Midwest Generation to ComEd under the sale agreement, including the environmental indemnity, may be discharged in the bankruptcy proceeding. In such circumstances, ComEd (and Generation, through ComEd) may only have an unsecured claim against EME and Midwest Generation for the environmental remediation costs that would have otherwise been obligations of EME and Midwest Generation under the sale agreement. This unsecured claim may yield a fractional, or possibly no, recovery for ComEd and Generation.

On October 18, 2013, NRG Energy entered into an agreement to buy EME's portfolio of generation. EME may continue to solicit alternative transaction proposals from third parties through December 6, 2013. Any such transaction would require the approval of the U.S. Bankruptcy Court. ComEd and Generation are currently evaluating the terms of the agreements to determine the impact they could have on the bankruptcy proceedings and ComEd s and Generation s claims.

ComEd and Generation continue to monitor the bankruptcy proceedings and available public information as to potential environmental exposures regarding the Midwest Generation plant sites. Midwest Generation publicly disclosed in its quarter ending June 30, 2013 Form 10-Q that (i) it has accrued a probable amount of approximately $8 million for estimated environmental investigation and remediation costs under CERCLA, or similar laws, for the investigation and remediation of contaminated property at four Midwest Generation plant sites, (ii) it has identified stations for which a reasonable estimate for investigation and/ or remediation cannot be made and (iii) it and the Illinois EPA entered into Compliance Commitment Agreements outlining specified environmental remediation measures and groundwater monitoring activities to be undertaken at its Crawford, Powerton, Joliet, Will County and Waukegan generating stations. At this time, however, ComEd and Generation do not have sufficient information to reasonably assess the potential likelihood or magnitude of any such exposures. Further, Midwest Generation s bankruptcy process will likely extend into mid-2014, and unless there is a successful transaction involving NRG Energy, the outcome is uncertain, including whether the facilities will continue to operate and the identity or financial wherewithal of potential future plant owners. For these reasons, ComEd and Generation are unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to the generating stations, and no liability has been recorded as of September 30, 2013. Any liability imposed on ComEd or Generation for environmental matters relating to the generating stations could have a material adverse impact on their future results of operations and cash flows.

Solid and Hazardous Waste

Cotter Corporation. The U.S. EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon s 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the U.S. EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. The current estimated cost of

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

the anticipated landfill cover remediation for the site is approximately $42 million, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability. By letter dated January 11, 2010, the U.S. EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the U.S. EPA for review. In June 2012, the U.S. EPA requested that the PRPs perform additional analysis and groundwater sampling as part of the supplemental feasibility study that could take up to one year to complete, and subsequently requested additional analysis sampling and modeling to be conducted in 2013 and 2014. In light of these additional requests, it is unknown when the U.S EPA will propose a remedy for public comment. Thereafter the U.S. EPA will select a final remedy and enter into a Consent Decree with the PRPs to effectuate the remedy. A complete excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the U.S. EPA would require a complete excavation remedy is remote.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government s clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd s indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. government s Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2014 so that settlement discussions could proceed. Based on Exelon s preliminary review, it appears probable that Exelon has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability.

On February 28, 2012, and April 12, 2012, two lawsuits were filed in the U.S. District Court for the Eastern District of Missouri against 15 and 14 defendants, respectively, including Exelon, Generation and ComEd (the Exelon defendants) and Cotter. The suits allege that individuals living in the North St. Louis area developed some form of cancer due to the defendants negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price Anderson Act. The complaints do not contain specific damage claims. On May 30, 2012, the plaintiffs filed voluntary motions to dismiss the Exelon defendants from both lawsuits which were subsequently granted. On October 23, 2012, a third lawsuit was filed in the same court on behalf of three additional plaintiffs against Cotter and seven other defendants, but not Exelon. On April 19, 2013, a fourth lawsuit was filed in the same court on behalf of two additional plaintiffs against Cotter and seven other defendants, but not Exelon. On June 18, 2013, a fifth lawsuit was filed in the same court on behalf of one plaintiff against eight defendants, including Cotter but not Exelon. On July 31, 2013, a sixth lawsuit was filed in the same court on behalf of two plaintiffs against Cotter and four other defendants, but not Exelon. The allegations in these latter four complaints mirror the initially filed lawsuits. In the event of a finding of liability, it is reasonably possible that Exelon would be considered liable due to its indemnification responsibilities of Cotter described above. On March 27, 2013, the U.S. District Court dismissed all state common law actions brought under the initial two lawsuits; and also found that the plaintiffs had not properly brought the actions under the Price Anderson Act. On July 8, 2013, the plaintiffs filed amended complaints under the Price Anderson Act. Cotter moved to dismiss the amended complaints and has motions currently pending before the court. At this stage of the litigation, Exelon cannot estimate a range of loss, if any.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

68th Street Dump. In 1999, the U.S. EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In March 2004, BGE and other PRPs formed the 68th Street Coalition and entered into consent order negotiations with the U.S. EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the U.S. EPA and 19 of the PRPs, including BGE, with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The potentially responsible parties submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the U.S. EPA are still subject to U.S. EPA review and selection of a remedy, the range of estimated clean-up costs to be allocated among all of the PRPs is in the range of $50 million to $64 million. On September 30, 2013, EPA issued its Record of Decision specifying the remedies to be implemented at the site based on the information and recommendations of the PRP investigation. The costs to implement these remedies are still expected to be in the range of $50 million to $64 million. The U.S. EPA is expected to make a final selection of one of the alternatives in 2013. Based on Exelon s preliminary review, it appears probable that Exelon has liability and has established an appropriate accrual for its share of the estimated clean-up costs. BGE is indemnified by a wholly owned subsidiary of Generation for most of the costs related to this settlement and clean-up of the site.

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

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

Climate Change Regulation. Exelon is subject to climate change regulation or legislation at the Federal, regional and state levels. In 2007, the U.S. Supreme Court ruled that GHG emissions are pollutants subject to regulation under the new motor vehicle provisions of the Clean Air Act. Consequently, on December 7, 2009, the U.S. EPA issued an endangerment finding under Section 202 of the Clean Air Act regarding GHGs from new motor vehicles and on April 1, 2010 issued final regulations limiting GHG emissions from cars and light trucks effective on January 2, 2011. While such regulations do not specifically address stationary sources, such as a generating plant, it is the U.S. EPA s position that the regulation of GHGs under the mobile source provisions of the Clean Air Act has triggered the permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources effective January 2, 2011. Therefore, on May 13, 2010, the U.S. EPA issued final regulations (the Tailoring Rule) relating to these provisions of the Clean Air Act for major stationary sources of GHG emissions that apply to new sources that emit greater than 100,000 tons per year, on a CO_2 equivalent basis, and to modifications to

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

existing sources that result in emissions increases greater than 75,000 tons per year on a CO_2 equivalent basis. These thresholds became effective January 2, 2011, apply for six years and will be reviewed by the U.S. EPA for future applicability thereafter. On July 2, 2012 the U.S. EPA declined to lower GHG permit thresholds in its final Step 3 Tailoring Rule update. The U.S. EPA will review permit thresholds again in a 2015 rulemaking process. On June 26, 2012, the United States Court of Appeals for the District of Columbia, in a *per curium* decision, dismissed industry and state petitions challenging the U.S. EPA s Tailpipe Rule for cars and light duty trucks, the endangerment finding for GHG s from stationary sources, and the Tailoring Rule. On October 15, 2013 the U.S. Supreme Court granted industry petitions to review one aspect of the PSD permitting regulations. Under the PSD regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case by case basis. Generation could be significantly affected by the regulations if it were to build new plants or modify existing plants.

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

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

The second rulemaking, under Section 111(d) of the Clean Air Act is to focus on modified, reconstructed and existing fossil power plants. The rulemaking is to be proposed no later than June 1, 2014, be finalized no later than June 1, 2015, and require that states submit to EPA their implementation plans no later than June 30, 2016. In developing this rulemaking, EPA is directed to consider a number of factors, including options to reduce costs, options to ensure the continued use of a range of energy sources and technologies, options that are consistent with reliable and affordable power, and options that allow for the use of market-based instruments, performance standards and other regulatory flexibilities.

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

Litigation and Regulatory Matters

Except to the extent noted below, the circumstances set forth in Note 19 of the Exelon 2012 Form 10-K describe, in all material respects, the current status of litigation matters. The following is an update to that discussion.

Asbestos Personal Injury Claims (Exelon, Generation and BGE)

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

At September 30, 2013 and December 31, 2012, Generation had reserved approximately $65 million and $63 million, respectively, in total for asbestos-related bodily injury claims. As of September 30, 2013, approximately $17 million of this amount related to 211 open claims presented to Generation, while the remaining $48 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary.

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

Approximately 480 individuals who were never employees of BGE or certain Constellation subsidiaries have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and certain Constellation subsidiaries in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or certain Constellation subsidiaries and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation s financial results.

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

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

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

Continuous Power Interruption (ComEd)

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Following the ICC s June 26, 2013 denial of ComEd s request for rehearing, on June 27, 2013 ComEd filed an appeal of both the summer and winter storm dockets with the Illinois Appellate Court regarding the ICC s interpretation of Section 16-125 of the Illinois Public Utilities Act. ComEd cannot predict the outcome of appeals.

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

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

Securities Class Action (Exelon)

Three federal securities class action lawsuits were filed in the United States District Courts for the Southern District of New York and the District of Maryland between September 2008 and November 2008 against Constellation. The cases were filed on behalf of a proposed class of persons who acquired publicly traded securities, including the Series A Junior Subordinated Debentures (Debentures), of Constellation between January 30, 2008 and September 16, 2008, and who acquired Debentures in an offering completed in June 2008. The securities class actions generally allege that Constellation, a number of its former officers or directors, and the underwriters violated the securities laws by issuing a false and misleading registration statement and prospectus in connection with Constellation s June 27, 2008 offering of the Debentures. The securities class actions also allege that Constellation issued false or misleading statements or was aware of material undisclosed information which contradicted public statements, including in connection with its announcements of financial results for 2007, the fourth quarter of 2007, the first quarter of 2008 and the second quarter of 2008 and the filing of its first quarter 2008 Form 10-Q. The securities class actions sought, among other things, certification of the cases as class actions, compensatory damages, reasonable costs and expenses, including counsel fees, and rescission damages.

The Southern District of New York granted the defendants motion to transfer the two securities class actions filed in Maryland to the District of Maryland, and the actions have since been transferred for coordination with the securities class action filed there. On May 9, 2013, the federal court in Maryland preliminarily approved the settlement of Constellation s 2008 Securities Class Action for a payment of $4 million, which will be paid by Constellation s insurer. Notice of the settlement was provided to class members in June 2013 and the court approved the final settlement on November 4, 2013. This settlement will resolve all of Constellation s litigation arising from the 2008 Securities Class Action lawsuit.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Baltimore City Franchise Taxes (BGE)

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

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

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

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

See Note 12 Income Taxes for information regarding the Registrants income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

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

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2013 and 2012:

Three Months Ended September 30, 2013	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory agreement units	$ 138	$ 138	$	$	$
Non-regulatory agreement units	35	35			
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	103	103			
Non-regulatory agreement units	46	46			
Net unrealized losses on pledged assets					
Zion Station decommissioning	(9)	(9)			
Regulatory offset to decommissioning trust fund-related activities(b)	(189)	(189)			
Total decommissioning-related activities	124	124			
Investment income	1				2(c)
Long-term lease income	7				
AFUDC Equity	4		2	1	1
Other	19	10	5		1
Other, net	$ 155	$ 134	$ 7	$ 1	$ 4

150

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory agreement units	$ 221	$ 221	$	$	$
Non-regulatory agreement units	65	65			
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	196	196			
Non-regulatory agreement units	70	70			
Net unrealized losses on pledged assets					
Zion Station decommissioning	(5)	(5)			
Regulatory offset to decommissioning trust fund-related activities(b)	(338)	(338)			
Total decommissioning-related activities	209	209			
Investment income (expense)	6	(1)		(1)	7(c)
Long-term lease income	20				
Interest income related to uncertain income tax positions	24	3		1	
AFUDC Equity	16		8	3	5
Other	36	18	10	1	1
Other, net	$ 311	$ 229	$ 18	$ 4	$ 13

Three Months Ended September 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory agreement units	$ 33	$ 33	$	$	$
Non-regulatory agreement units	10	10			
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	202	202			
Non-regulatory agreement units	71	71			
Net unrealized gains on pledged assets					
Zion Station decommissioning	22	22			
Regulatory offset to decommissioning trust fund-related activities(b)	(208)	(208)			
Total decommissioning-related activities	130	130			
Investment income	5	1			3
Long-term lease income	7				
Interest income related to uncertain income tax positions		1	1		
Credit facility termination fees	(43)	(43)			
AFUDC Equity	4		1	1	2
Other	(2)	(6)	3	1	
Other, net	$ 101	$ 83	$ 5	$ 2	$ 5

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory agreement units	$ 143	$ 143	$	$	$
Non-regulatory agreement units	77	77			
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	352	352			
Non-regulatory agreement units	101	101			
Net unrealized gains on pledged assets					
Zion Station decommissioning	60	60			
Regulatory offset to decommissioning trust fund-related activities(b)	(453)	(453)			
Total decommissioning-related activities	280	280			
Investment income	15	2	1	2	9
Long-term lease income	22				
Interest income related to uncertain income tax positions	14	1	1		
Credit facility termination fees	(85)	(85)			
AFUDC Equity	11		2	3	8
Other	(4)	(13)	8	1	1
Other, net	$ 253	$ 185	$ 12	$ 6	$ 18

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.
(b) Includes the elimination of NDT fund-related activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 13 Asset Retirement Obligations of the Exelon 2012 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
(c) Relates to the cash return on BGE s rate stabilization deferral. See Note 5 Regulatory Matters for additional information regarding the rate stabilization deferral.

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants Consolidated Statements of Cash Flows for the nine months ended September 30, 2013 and 2012:

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$ 1,263	$ 540	$ 396	$ 154	$ 184
Regulatory assets	89		62	7	34
Amortization of intangible assets, net	24	24			
Amortization of energy contract assets and liabilities(a)	731	812			
Nuclear fuel(a)	628	628			
ARO accretion(b)	174	174			
Total depreciation, amortization, accretion and depletion	$ 2,909	$ 2,178	$ 458	$ 161	$ 218

(a) Included in revenues or fuel expense, or operating revenues on the Registrants Consolidated Statements of Operations and Comprehensive Income.
(b) Included in operating and maintenance expense on the Registrants Consolidated Statements of Operations.

Nine Months Ended September 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 621	$ 259	$ 231	$ 32	$ 41
Loss in equity method investments	(7)	(7)			
Provision for uncollectible accounts	83	16	(6)	48	25
Stock-based compensation costs	99				
Other decommissioning-related activity(a)	(110)	(110)			
Energy-related options(b)	87	87			
Amortization of regulatory asset related to debt costs	9		7	2	
Amortization of rate stabilization deferral	49				49
Amortization of debt fair value adjustment	(28)	(28)			
Discrete impacts from EIMA(c)	(206)		(206)		
Amortization of debt costs	13	7	3	2	1
Merger integration costs(d)	(6)				(6)
Impairment of investments in direct financing leases(e)	14				
Increase in inventory reserve	7	7			
Impairment charges(f)	149	149			
Other	(36)	(5)	(3)		(5)
Total other non-cash operating activities	$ 738	$ 375	$ 26	$ 84	$ 105
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ (47)	$	$ (63)	$ (10)	$ 26
Other regulatory assets and liabilities	(50)		(35)		(85)
Settlement of interest rate swaps(j)	26				
Other current assets	(169)	(123)	(3)	(31)	(35)
Other noncurrent assets and liabilities	205	(40)	261(g)	(6)	(25)
Total changes in other assets and liabilities	$ (35)	$ (163)	$ 160	$ (47)	$ (119)
Non-cash investing and financing activities:					
Consolidated VIE dividend to non-controlling interest	$ 63	$ 63	$	$	$
Indemnification of like-kind exchange position(h)			175		

Total non-cash investing and financing activities:	$	63	$	63	$	175	$		$	

153

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 606	$ 259	$ 212	$ 38	$ 44
Provision for uncollectible accounts	120	14	38	46	28
Stock-based compensation costs	75				
Other decommissioning-related activity(a)	(108)	(108)			
Energy-related options(b)	119	119			
Amortization of regulatory asset related to debt costs	13		10	2	1
Amortization of rate stabilization deferral	39				49
Amortization of debt fair value adjustment	(49)	(23)			
Discrete impacts from EIMA(c)	43		43		
Merger-related commitments(i)	179	35			28
Severance cost	120	34		1	
Loss in equity method investments	69	69			
Other	9	23	7	9	(2)
Total other non-cash operating activities	$ 1,235	$ 422	$ 310	$ 96	$ 148
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 20	$	$ 21	$ (3)	$ 21
Other regulatory assets and liabilities	(454)		(65)	7	(80)
Other current assets	52	(85)	(8)	(56)	(25)
Other noncurrent assets and liabilities	(40)	(110)	(72)	(5)	7
Total changes in other assets and liabilities	$ (422)	$ (195)	$ (124)	$ (57)	$ (77)
Non-cash investing and financing activities:					
Merger with Constellation, common stock issued	$ 7,365	$ 5,258	$	$	$

(a) Includes the elimination of NDT fund-related activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 13 of the Exelon 2012 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 5 Regulatory Matters for more information.
(d) Relates to integration costs to achieve distribution synergies related to the merger transaction. See Note 5 Regulatory Matters for more information.
(e) Relates to an other than temporary decline in the estimated residual value of one of Exelon s direct financing leases. See Note 7 Impairment of Long-Lived Assets for more information.
(f) Relates to the cancellation of uprate projects and write down of certain wind projects at Generation. See Note 7 Impairment of Long-Lived Assets for additional information.
(g) Relates primarily to interest payable related to like-kind exchange tax position. See Note 12 Income Taxes for discussion of the like-kind exchange tax position.
(h) See Note 12 Income Taxes for discussion of the like-kind exchange tax position.
(i) See Note 4 Mergers and Acquisitions for more information on merger-related commitments.
(i) Relates to settlement of forward starting interest rate swaps that Exelon entered into in anticipation of the Continental Wind, LLC non-recourse project financing that was completed on September 30, 2013. See Note 10 Derivative Financial Instruments for more information on interest rate swaps.

DOE Smart Grid Investment Grant (Exelon, PECO and BGE). For the nine months ended September 30, 2013, Exelon, PECO and BGE have included in the Capital expenditures line item under investing activities of

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

the cash flow statement capital expenditures of $68 million, $22 million and $46 million, respectively, and reimbursements of $64 million, $30 million and $34 million, respectively, related to PECO's and BGE's DOE SGIG programs. For the nine months ended September 30, 2012, Exelon, PECO and BGE have included in the Capital expenditures line item under investing activities of the cash flow statement capital expenditures of $75 million, $45 million and $30 million, respectively, and reimbursements of $85 million, $55 million and $30 million, respectively, related to PECO's and BGE's DOE SGIG programs. See Note 5 - Regulatory Matters for additional information regarding the DOE SGIG.

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants as of September 30, 2013 and December 31, 2012.

September 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$ 13,366(a)	$ 6,848(a)	$ 3,107	$ 2,914	$ 2,658
Accounts receivable:					
Allowance for uncollectible accounts	302	72	73	119	38

December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$ 12,184(b)	$ 6,014(b)	$ 2,998	$ 2,797	$ 2,595
Accounts receivable:					
Allowance for uncollectible accounts	293	84	70	99	40

(a) Includes accumulated amortization of nuclear fuel in the reactor core of $2,365 million.
(b) Includes accumulated amortization of nuclear fuel in the reactor core of $2,078 million.

PECO Installment Plan Receivables (Exelon and PECO)

PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $22 million as of September 30, 2013 and $18 million as of December 31, 2012. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1 Significant Account Policies of the Exelon 2012 Form 10-K. The allowance for uncollectible accounts balance associated with these receivables at September 30, 2013 of $22 million consists of $1 million, $4 million and $17 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2012 of $15 million consists of $1 million, $3 million and $11 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of September 30, 2013 and December 31, 2012 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1 Significant Accounting Policies of the Exelon 2012 Form 10-K.

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

Exelon has nine reportable segments, ComEd, PECO, BGE and Generation s six power marketing reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other regions not considered individually significant referred to collectively as Other Regions ; including the South, West and Canada. Generation s expanded number of reportable segments is the result of the acquisition of Constellation on March 12, 2012. ComEd, PECO and BGE each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. Exelon evaluates the performance of ComEd, PECO and BGE based on net income.

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

Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.

Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the entire United States footprint of MISO, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.

New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

New York represents operations within ISO-NY, which covers the state of New York in its entirety.

ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.

Other Regions not considered individually significant:

South represents operations in the FRCC and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation s South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.

West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.

Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

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

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

An analysis and reconciliation of the Registrants reportable segment information to the respective information in the consolidated financial statements for the three and nine months ended September 30, 2013 and 2012 is as follows:

Three Months Ended September 30, 2013 and 2012

	Generation(a)	ComEd	PECO	BGE	Other(b)	Intersegment Eliminations	Exelon
Total revenues(c):							
2013	$ 4,255	$ 1,156	$ 728	$ 737	$ 294	$ (668)	$ 6,502
2012	4,031	1,484	806	720	336	(798)	6,579
Intersegment revenues(d):							
2013	$ 373	$ 1	$ 1	$ 2	$ 294	$ (669)	$ 2
2012	459		1	4	337	(798)	3
Net income (loss):							
2013	$ 485	$ 126	$ 92	$ 53	$ (20)	$	$ 736
2012	87	90	123		(3)		297
Total assets:							
September 30, 2013	$ 40,498	$ 23,686	$ 9,745	$ 7,657	$ 9,563	$ (11,488)	$ 79,661
December 31, 2012	40,681	22,905	9,353	7,506	10,432	(12,316)	78,561

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. Intersegment revenues for Generation for the three months ended September 30, 2013 include revenue from sales to PECO of $82 million and sales to BGE of $144 million in the Mid-Atlantic region, and sales to ComEd of $143 million in the Midwest. For the three months ended September 30, 2012 intersegment revenues for Generation include revenue from sales to PECO of $171 million and sales to BGE of $120 million in the Mid-Atlantic region, and sales to ComEd of $180 million in the Midwest region, net of $15 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation.

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

(c) For the three months ended September 30, 2013 and 2012, utility taxes of $21 million and $28 million, respectively, are included in revenues and expenses for Generation. For the three months ended September 30, 2013 and 2012, utility taxes of $65 million and $67 million, respectively, are included in revenues and expenses for ComEd. For the three months ended September 30, 2013 and 2012, utility taxes of $33 million and $40 million, respectively, are included in revenues and expenses for PECO. For the three months ended September 30, 2013 and 2012, utility taxes of $20 million and $20 million, respectively, are included in revenues and expenses for BGE.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Generation total revenues (three months ended):

	2013			2012		
	Revenues from external customers(a)	Intersegment revenues	Total Revenues	Revenues from external customers(a)	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 1,381	$ 10	$ 1,391	$ 1,428	$ (11)	$ 1,417
Midwest	1,018	(5)	1,013	1,193	7	1,200
New England	341	(1)	340	390	1	391
New York	198	(14)	184	183	2	185
ERCOT	430	(3)	427	532	1	533
Other Regions(b)	278	(7)	271	317	12	329
Total Revenues for Reportable Segments	3,646	(20)	3,626	4,043	12	4,055
Other(c)	609	20	629	(12)	(12)	(24)
Total Generation Consolidated Operating Revenues	$ 4,255	$	$ 4,255	$ 4,031	$	$ 4,031

(a) Includes all electric sales to third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions include the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of $125 million and $404 million, for the three months ended September 30, 2013 and 2012, respectively, and elimination of intersegment revenues.

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

	2013			2012		
	RNF from external customers(a)	Intersegment RNF	Total RNF	RNF from external customers(a)	Intersegment RNF	Total RNF
Mid-Atlantic	$ 857	$ 7	$ 864	$ 919	$ (11)	$ 908
Midwest	606	(5)	601	723	7	730
New England	52	10	62	80	1	81
New York	29	(38)	(9)	11	2	13
ERCOT	222	(78)	144	158		158
Other Regions(b)	116	(75)	41	30	12	42
Total Revenues net of purchased power and fuel expense for Reportable Segments	1,882	(179)	1,703	1,921	11	1,932
Other(c)	194	179	373	(12)	(11)	(23)
Total Generation Revenues net of purchased power and fuel expense	$ 2,076	$	$ 2,076	$ 1,909	$	$ 1,909

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions includes the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of $44 million and $257 million for the three months ended September 30, 2013 and 2012, respectively.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2013 and 2012

	Generation(a)	ComEd	PECO	BGE(b)	Other(c)	Intersegment Eliminations	Exelon
Total revenues(d):							
2013	$ 11,858	$ 3,395	$ 2,295	$ 2,271	$ 909	$ (2,003)	$ 18,725
2012	10,539	4,154	2,396	1,388	1,049	(2,291)	17,235
Intersegment revenues(e):							
2013	$ 1,083	$ 2	$ 1	$ 10	$ 909	$ (2,003)	$ 2
2012	1,233	2	3	7	1,050	(2,291)	4
Net income (loss):							
2013	$ 795	$ 140	$ 292	$ 160	$ (152)	$	$ 1,235
2012	419	219	300	(50)	(101)		787

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. Intersegment revenues for Generation for the nine months ended September 30, 2013 include revenue from sales to PECO of $321 million and sales to BGE of $356 million in the Mid-Atlantic region, and sales to ComEd of $409 million in the Midwest region, net of $7 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation. For the nine months ended September 30, 2012 intersegment revenues for Generation include revenue from sales to PECO of $407 million in the Mid-Atlantic region and sales to BGE of $223 million in the Mid-Atlantic region, and sales to ComEd of $631 million in the Midwest region, net of $30 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation.

(b) Amounts represent activity recorded at BGE from March 12, 2012, the closing date of the merger, through September 30, 2012.

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

(d) For the nine months ended September 30, 2013 and 2012, utility taxes of $60 million and $60 million, respectively, are included in revenues and expenses for Generation. For the nine months ended September 30, 2013 and 2012, utility taxes of $182 million and $182 million, respectively, are included in revenues and expenses for ComEd. For the nine months ended September 30, 2013 and 2012, utility taxes of $97 million and $108 million, respectively, are included in revenues and expenses for PECO. For the nine months ended September 30, 2013 and period of March 12, 2012 through September 30, 2012, utility taxes of $62 million and $42 million, respectively, are included in revenues and expenses for BGE.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Generation total revenues (nine months ended):

	2013			2012		
	Revenues from external customers(a)	Intersegment revenues	Total Revenues	Revenues from external customers(a)	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 3,932	$ 11	$ 3,943	$ 3,832	$ (43)	$ 3,789
Midwest	3,274	(3)	3,271	3,600	19	3,619
New England	942	(9)	933	776	36	812
New York	547	(20)	527	394	(22)	372
ERCOT	1,042	(8)	1,034	1,073	1	1,074
Other Regions(b)	708	29	737	611	40	651
Total Revenues for Reportable Segments	10,445		10,445	10,286	31	10,317
Other(c)	1,413		1,413	253	(31)	222
Total Generation Consolidated Operating Revenues	$ 11,858	$	$ 11,858	$ 10,539	$	$ 10,539

(a) Includes all wholesale and retail electric sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions include the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date of $603 million and $1,089 million, for the nine months ended September 30, 2013 and 2012, respectively, and elimination of intersegment revenues.

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

	2013			2012		
	RNF from external customers(a)	Intersegment RNF	Total RNF	RNF from external customers(a)	Intersegment RNF	Total RNF
Mid-Atlantic	$ 2,477	$ (2)	$ 2,475	$ 2,605	$ (44)	$ 2,561
Midwest	2,002	(1)	2,001	2,291	19	2,310
New England	156	(14)	142	144	36	180
New York	14	(31)	(17)	82	(22)	60
ERCOT	477	(120)	357	311	1	312
Other Regions(b)	238	(91)	147	49	41	90
Total Revenues net of purchased power and fuel expense for Reportable Segments	5,364	(259)	5,105	5,482	31	5,513
Other(c)	200	259	459	39	(31)	8
	$ 5,564	$	$ 5,564	$ 5,521	$	$ 5,521

Total Generation Revenues net of purchased power and fuel expense	

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions includes the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date of $386 million and $793 million, for the nine months ended September 30, 2013 and 2012, respectively.

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

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

Exelon Corporation

General

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

- *Generation,* one of the largest competitive electric generation companies in the United States as measured by owned and contracted MW, physically delivers and markets power across multiple geographic regions through its customer-facing business, Constellation. Generation operates as an integrated business, leveraging its owned and contracted electric generation capacity to market and sell power to wholesale and retail supply customers. Generation s customers include distribution utilities, municipalities, cooperatives, financial institutions, and commercial, industrial, governmental, and residential customers in competitive markets. Generation also sells natural gas and renewable and other energy-related offerings, and engages in natural gas exploration and production activities.

- *ComEd,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.

- *PECO,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.

- *BGE,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

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

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

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

Executive Overview

Financial Results. The following consolidated financial results reflect the results of Exelon for the three and nine months ended September 30, 2013 compared to the corresponding periods in 2012. The financial results for the nine months ended September 30, 2012 only include the operations of Constellation and BGE from March 12, 2012, the date of the merger with Constellation, through September 30, 2012. All amounts presented below are before the impact of income taxes, except as noted.

	Three Months Ended September 30, 2013						2012	Favorable (Unfavorable)
	Generation	**ComEd**	**PECO**	**BGE**	**Other**	**Exelon**	**Exelon**	**Variance**
Operating revenues	$ 4,255	$ 1,156	$ 728	$ 737	$ (374)	$ 6,502	$ 6,579	$ (77)
Purchased power and fuel	2,179	301	289	346	(372)	2,743	3,026	283
Revenue net of purchased power and fuel(a)	2,076	855	439	391	(2)	3,759	3,553	206
Other operating expenses								
Operating and maintenance	1,076	333	186	146	(6)	1,735	2,170	435
Depreciation and amortization	218	164	57	78	13	530	500	(30)
Taxes other than income	98	80	41	53	5	277	290	13
Total other operating expenses	1,392	577	284	277	12	2,542	2,960	418
Equity in earnings of unconsolidated affiliates	37					37	10	27
Operating income (loss)	721	278	155	114	(14)	1,254	603	651
Other income and (deductions)								
Interest expense, net	(82)	(74)	(29)	(29)	(20)	(234)	(246)	12
Other, net	134	7	1	4	9	155	101	54
Total other income and (deductions)	52	(67)	(28)	(25)	(11)	(79)	(145)	66
Income (loss) before income taxes	773	211	127	89	(25)	1,175	458	717
Income taxes	288	85	35	36	(5)	439	161	(278)
Net income (loss)	485	126	92	53	(20)	736	297	439
Net (loss) income attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	(5)			3		(2)	1	3
Net income (loss) attributable to common shareholders	$ 490	$ 126	$ 92	$ 50	$ (20)	$ 738	$ 296	$ 442

	Nine Months Ended September 30, 2013						2012	Favorable (Unfavorable)
	Generation	ComEd	PECO	BGE	Other	Exelon	Exelon	Variance
Operating revenues	$ 11,858	$ 3,395	$ 2,295	$ 2,271	$ (1,094)	$ 18,725	$ 17,235	$ 1,490
Purchased power and fuel	6,294	931	953	1,059	(1,094)	8,143	7,398	(745)
Revenue net of purchased power and fuel(a)	5,564	2,464	1,342	1,212		10,582	9,837	745
Other operating expenses								
Operating and maintenance	3,377	1,020	554	450	(10)	5,391	5,979	588
Depreciation and amortization	643	501	171	252	39	1,606	1,376	(230)
Taxes other than income	292	225	121	162	25	825	737	(88)
Total other operating expenses	4,312	1,746	846	864	54	7,822	8,092	270
Equity in earnings (loss) of unconsolidated affiliates	7					7	(69)	76
Operating income (loss)	1,259	718	496	348	(54)	2,767	1,676	1,091
Other income and (deductions)								
Interest expense, net	(257)	(503)	(86)	(94)	(170)	(1,110)	(697)	(413)
Other, net	229	18	4	13	47	311	253	58
Total other income and (deductions)	(28)	(485)	(82)	(81)	(123)			