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

FORM 10-Q

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

For the Quarterly Period Ended June 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 (an Illinois corporation) 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210

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

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

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

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

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

The number of shares outstanding of each registrant's common stock as of June 30, 2013 was:

Exelon Corporation Common Stock, without par value	856,563,385
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,818
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities	
Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon in its corporate capacity as a holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
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
CPI	Consumer Price Index
CPUC	California Public Utilities Commission

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
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
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midwest Independent Transmission System Operator, Inc.

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
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
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

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
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

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FILING FORMAT

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

FORWARD-LOOKING STATEMENTS

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

WHERE TO FIND MORE INFORMATION

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

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

(In millions, except per share data)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Operating revenues	$ 6,141	$ 5,966	$12,223	$10,656
Operating expenses				
Purchased power and fuel	2,419	2,606	5,400	4,371
Operating and maintenance	1,892	1,841	3,656	3,809
Depreciation and amortization	533	494	1,076	876
Taxes other than income	271	254	548	448
Total operating expenses	5,115	5,195	10,680	9,504
Equity in loss of unconsolidated affiliates	(21)	(57)	(30)	(79)
Operating income	1,005	714	1,513	1,073
Other income and (deductions)				
Interest expense	(246)	(250)	(863)	(439)
Interest expense to affiliates, net	(6)	(6)	(13)	(12)
Other, net	(17)	(43)	155	152
Total other income and (deductions)	(269)	(299)	(721)	(299)
Income before income taxes	736	415	792	774
Income taxes	239	126	294	284
Net income	497	289	498	490
Net income attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	7	3	12	4
Net income attributable to common shareholders	490	286	486	486
Comprehensive income (loss), net of income taxes				
Net income	497	289	498	490
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	1
Actuarial loss reclassified to periodic cost	50	41	100	82
Transition obligation reclassified to periodic cost	—	—	—	2
Pension and non-pension postretirement benefit plans valuation adjustment	2	(3)	77	(11)
Deferred compensation unit valuation adjustment	10	—	10	—
Change in unrealized (loss) gain on cash flow hedges	(65)	(156)	(123)	59
Change in unrealized income on equity investments	8	6	36	6
Change in unrealized loss on foreign currency translation	(5)	(2)	(6)	(2)
Change in unrealized loss on marketable securities	—	(1)	(1)	—
Other comprehensive income (loss)	—	(114)	94	137
Comprehensive income	$ 497	$ 175	$ 592	$ 627
Average shares of common stock outstanding:				
Basic	856	853	856	779
Diluted	860	856	859	781
Earnings per average common share:				
Basic	$ 0.57	$ 0.34	$ 0.57	$ 0.62
Diluted	$ 0.57	$ 0.33	$ 0.57	$ 0.62
Dividends per common share	$ 0.31	$ 0.53	$ 0.84	$ 1.05

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Cash flows from operating activities		
Net income	$ 498	$ 490
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	1,972	1,895
Deferred income taxes and amortization of investment tax credits	(468)	227
Net fair value changes related to derivatives	(28)	(323)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(27)	(70)
Other non-cash operating activities	576	959
Changes in assets and liabilities:		
Accounts receivable	131	414
Inventories	(18)	45
Accounts payable, accrued expenses and other current liabilities	(583)	(1,063)
Option premiums paid, net	(10)	(108)
Counterparty collateral (posted) received, net	(259)	451
Income taxes	705	259
Pension and non-pension postretirement benefit contributions	(284)	(90)
Other assets and liabilities	133	(373)
Net cash flows provided by operating activities	2,338	2,713
Cash flows from investing activities		
Capital expenditures	(2,518)	(2,800)
Proceeds from nuclear decommissioning trust fund sales	1,448	5,371
Investment in nuclear decommissioning trust funds	(1,565)	(5,483)
Cash and restricted cash acquired from Constellation	—	964
Proceeds from sales of investments	4	12
Purchases of investments	(3)	(5)
Change in restricted cash	22	(15)
Other investing activities	63	(12)
Net cash flows used in investing activities	(2,549)	(1,968)
Cash flows from financing activities		
Changes in short-term debt	662	179
Issuance of long-term debt	509	850
Retirement of long-term debt	(616)	(649)
Redemption of preferred securities	(93)	—
Dividends paid on common stock	(716)	(773)
Dividends paid to former Constellation shareholders	—	(51)
Proceeds from employee stock plans	32	42
Other financing activities	(62)	(10)
Net cash flows used in financing activities	(284)	(412)
(Decrease) increase in cash and cash equivalents	(495)	333
Cash and cash equivalents at beginning of period	1,486	1,016
Cash and cash equivalents at end of period	$ 991	$ 1,349

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 956	$ 1,411
Cash and cash equivalents of variable interest entities	35	75
Restricted cash and investments	61	86
Restricted cash and investments of variable interest entities	53	47
Accounts receivable, net		
Customer ($286 and $289 gross accounts receivable pledged as collateral as of June 30, 2013 and December 31, 2012, respectively)	2,609	2,795
Other	1,224	1,141
Accounts receivable, net, variable interest entities	252	292
Mark-to-market derivative assets	845	938
Unamortized energy contract assets	573	886
Inventories, net		
Fossil fuel	214	246
Materials and supplies	805	768
Deferred income taxes	288	131
Regulatory assets	804	764
Other	690	560
Total current assets	9,409	10,140
Property, plant and equipment, net	45,994	45,186
Deferred debits and other assets		
Regulatory assets	6,519	6,497
Nuclear decommissioning trust funds	7,463	7,248
Investments	1,171	1,184
Investments in affiliates	22	22
Investment in CENG	1,876	1,849
Goodwill	2,625	2,625
Mark-to-market derivative assets	772	937
Unamortized energy contracts assets	856	1,073
Pledged assets for Zion Station decommissioning	538	614
Other	1,175	1,186
Total deferred debits and other assets	23,017	23,235
Total assets	$ 78,420	$ 78,561

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 662	$ —
Short-term notes payable — accounts receivable agreement	210	210
Long-term debt due within one year	1,944	975
Long-term debt due within one year of variable interest entities	87	72
Accounts payable	2,210	2,446
Accounts payable of variable interest entities	147	202
Accrued expenses	1,382	1,800
Deferred income taxes	45	58
Regulatory liabilities	357	368
Mark-to-market derivative liabilities	147	352
Unamortized energy contract liabilities	360	455
Other	823	853
Total current liabilities	8,374	7,791
Long-term debt	16,121	17,190
Long-term debt to financing trusts	648	648
Long-term debt of variable interest entities	449	508
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	11,519	11,551
Asset retirement obligations	5,202	5,074
Pension obligations	3,164	3,428
Non-pension postretirement benefit obligations	2,706	2,662
Spent nuclear fuel obligation	1,020	1,020
Regulatory liabilities	4,044	3,981
Mark-to-market derivative liabilities	178	281
Unamortized energy contract liabilities	399	528
Payable for Zion Station decommissioning	373	432
Other	2,635	1,650
Total deferred credits and other liabilities	31,240	30,607
Total liabilities	56,832	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 June 30, 2013 and December 31, 2012, respectively)	16,693	16,632
Treasury stock, at cost (35 shares at June 30, 2013 and December 31, 2012, respectively)	(2,327)	(2,327)
Retained earnings	9,660	9,893
Accumulated other comprehensive loss, net	(2,673)	(2,767)
Total shareholders' equity	21,353	21,431
BGE preference stock not subject to mandatory redemption	193	193
Noncontrolling interest	42	106
Total equity	21,588	21,730
Total liabilities and shareholders' equity	$ 78,420	$ 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)	—	—	—	486	—	(1)	13	498
Long-term incentive plan activity	1,782	61	—	—	—	—	—	61
Common stock dividends	—	—	—	(719)	—	—	—	(719)
Consolidated VIE dividend to non-controlling interest	—	—	—	—	—	(63)	—	(63)
Redemption of preferred securities	—	—	—	—	—	—	(6)	(6)
Preferred and preference stock dividends	—	—	—	—	—	—	(7)	(7)
Other comprehensive income net of income taxes of $(67)	—	—	—	—	94	—	—	94
Balance, June 30, 2013	891,307	$16,693	$(2,327)	$ 9,660	$ (2,673)	$ 42	$ 193	$21,588

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	2013	2012	2013	2012
Operating revenues				
Operating revenues	$ 3,718	$ 3,345	$ 6,859	$ 5,718
Operating revenues from affiliates	352	420	744	790
Total operating revenues	4,070	3,765	7,603	6,508
Operating expenses				
Purchased power and fuel	1,946	1,852	4,114	2,896
Operating and maintenance	1,041	990	2,007	2,029
Operating and maintenance from affiliates	148	188	295	327
Depreciation and amortization	210	204	424	357
Taxes other than income	101	90	194	164
Total operating expenses	3,446	3,324	7,034	5,773
Equity in loss of unconsolidated affiliates	(21)	(57)	(30)	(79)
Operating income	603	384	539	656
Other income and (deductions)				
Interest expense	(93)	(85)	(176)	(138)
Other, net	(33)	(76)	95	103
Total other income and (deductions)	(126)	(161)	(81)	(35)
Income before income taxes	477	223	458	621
Income taxes	149	58	148	289
Net income	328	165	310	332
Net loss attributable to noncontrolling interests	(2)	(1)	(1)	(2)
Net income attributable to membership interest	330	166	311	334
Comprehensive income (loss), net of income taxes				
Net income	328	165	310	332
Other comprehensive (loss) income, net of income taxes				
Change in unrealized loss on cash flow hedges	(137)	(266)	(267)	(14)
Change in unrealized income on equity investments	8	6	36	6
Change in unrealized loss on foreign currency translation	(5)	(2)	(6)	(2)
Change in unrealized loss on marketable securities	—	(1)	(1)	(1)
Other comprehensive loss	(134)	(263)	(238)	(11)
Comprehensive income (loss)	$ 194	$ (98)	$ 72	$ 321

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Cash flows from operating activities		
Net income	$ 310	$ 332
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	1,358	1,423
Deferred income taxes and amortization of investment tax credits	(44)	168
Net fair value changes related to derivatives	(21)	(307)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(27)	(70)
Other non-cash operating activities	315	318
Changes in assets and liabilities:		
Accounts receivable	88	306
Receivables from and payables to affiliates, net	(29)	(42)
Inventories	(38)	30
Accounts payable, accrued expenses and other current liabilities	(426)	(732)
Option premiums paid, net	(10)	(108)
Counterparty collateral (paid) received, net	(303)	443
Income taxes	265	314
Pension and non-pension postretirement benefit contributions	(120)	(35)
Other assets and liabilities	(168)	(174)
Net cash flows provided by operating activities	1,150	1,866
Cash flows from investing activities		
Capital expenditures	(1,277)	(1,820)
Proceeds from nuclear decommissioning trust fund sales	1,448	5,371
Investment in nuclear decommissioning trust funds	(1,565)	(5,483)
Change in restricted cash	(11)	6
Cash acquired from Constellation	—	708
Other investing activities	27	(66)
Net cash flows used in investing activities	(1,378)	(1,284)
Cash flows from financing activities		
Issuance of long-term debt	209	850
Retirement of long-term debt	(458)	(56)
Change in short-term debt	288	(42)
Changes in Exelon intercompany money pool borrowings	263	—
Distribution to member	(474)	(891)
Other financing activities	(49)	(9)
Net cash flows used in financing activities	(221)	(148)
(Decrease) increase in cash and cash equivalents	(449)	434
Cash and cash equivalents at beginning of period	671	496
Cash and cash equivalents at end of period	$ 222	$ 930

See the Combined Notes to Consolidated Financial Statements

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 187	$ 596
Cash and cash equivalents of variable interest entities	35	75
Restricted cash and cash equivalents of variable interest entities	27	16
Accounts receivable, net		
Customer	1,464	1,482
Other	347	472
Accounts receivable, net, variable interest entities	242	292
Mark-to-market derivative assets	845	938
Mark-to-market derivative assets with affiliates	—	226
Receivables from affiliates	123	141
Unamortized energy contract assets	573	886
Inventories, net		
Fossil fuel	133	130
Materials and supplies	648	626
Deferred income taxes	195	—
Other	488	331
Total current assets	5,307	6,211
Property, plant and equipment, net	19,678	19,531
Deferred debits and other assets		
Nuclear decommissioning trust funds	7,463	7,248
Investments	409	420
Investment in CENG	1,876	1,849
Mark-to-market derivative assets	740	924
Prepaid pension asset	1,982	1,975
Pledged assets for Zion Station decommissioning	538	614
Unamortized energy contract assets	856	1,073
Other	829	836
Total deferred debits and other assets	14,693	14,939
Total assets	$ 39,678	$ 40,681

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 288	$ —
Long-term debt due within one year	500	24
Long-term debt due within one year of variable interest entities	8	4
Accounts payable	1,134	1,346
Accounts payable of variable interest entities	147	202
Accrued expenses	812	1,116
Payables to affiliates	148	193
Borrowings from Exelon intercompany money pool	263	—
Deferred income taxes	35	128
Mark-to-market derivative liabilities	131	334
Unamortized energy contract liabilities	315	378
Other	321	372
Total current liabilities	4,102	4,097
Long-term debt	4,975	5,245
Long-term debt to affiliate	1,534	2,007
Long-term debt of variable interest entities	196	203
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,647	5,398
Asset retirement obligations	5,065	4,938
Non-pension postretirement benefit obligations	814	755
Spent nuclear fuel obligation	1,020	1,020
Payables to affiliates	2,433	2,397
Mark-to-market derivative liabilities	109	232
Unamortized energy contract liabilities	393	516
Payable for Zion Station decommissioning	373	432
Other	820	776
Total deferred credits and other liabilities	16,674	16,464
Total liabilities	27,481	28,016
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	8,873	8,876
Undistributed earnings	3,005	3,168
Accumulated other comprehensive income, net	275	513
Total member's equity	12,153	12,557
Noncontrolling interest	44	108
Total equity	12,197	12,665
Total liabilities and equity	$ 39,678	$ 40,681

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Unaudited)

	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Income, net	Noncontrolling Interest	Total Equity
Balance, December 31, 2012	$ 8,876	$ 3,168	$ 513	$ 108	$12,665
Net income (loss)	—	311	—	(1)	310
Noncontrolling interest acquired	(3)	—	—	—	(3)
Distribution to member	—	(474)	—	—	(474)
Consolidated VIE dividend to non-controlling interest	—	—	—	(63)	(63)
Other comprehensive loss, net of income taxes of $152	—	—	(238)	—	(238)
Balance, June 30, 2013	$ 8,873	$ 3,005	$ 275	$ 44	$12,197

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 June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Operating revenues				
Operating revenues	$ 1,080	$ 1,280	$ 2,238	$ 2,669
Operating revenues from affiliates	—	1	1	1
Total operating revenues	1,080	1,281	2,239	2,670
Operating expenses				
Purchased power	127	384	364	757
Purchased power from affiliate	121	203	266	451
Operating and maintenance	319	293	611	569
Operating and maintenance from affiliate	40	38	76	81
Depreciation and amortization	170	152	337	300
Taxes other than income	71	69	145	144
Total operating expenses	848	1,139	1,799	2,302
Operating income	232	142	440	368
Other income and (deductions)				
Interest expense	(72)	(71)	(422)	(150)
Interest expense to affiliates, net	(4)	(3)	(7)	(6)
Other, net	6	3	11	7
Total other income and (deductions)	(70)	(71)	(418)	(149)
Income before income taxes	162	71	22	219
Income taxes	66	29	8	90
Net income	96	42	14	129
Other comprehensive income, net of income taxes				
Change in unrealized gain on marketable securities	—	—	—	1
Other comprehensive income	—	—	—	1
Comprehensive income	$ 96	$ 42	$ 14	$ 130

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

(In millions)	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Cash flows from operating activities		
Net income	$ 14	$ 129
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	337	300
Deferred income taxes and amortization of investment tax credits	(226)	116
Other non-cash operating activities	39	241
Changes in assets and liabilities:		
Accounts receivable	18	(26)
Receivables from and payables to affiliates, net	(26)	(18)
Inventories	(11)	(7)
Accounts payable, accrued expenses and other current liabilities	20	(54)
Counterparty collateral received, net	45	8
Income taxes	240	149
Pension and non-pension postretirement benefit contributions	(119)	(12)
Other assets and liabilities	172	(104)
Net cash flows provided by operating activities	503	722
Cash flows from investing activities		
Capital expenditures	(711)	(585)
Proceeds from sales of investments	4	12
Purchases of investments	(3)	(5)
Change in restricted cash	(3)	—
Other investing activities	20	11
Net cash flows used in investing activities	(693)	(567)
Cash flows from financing activities		
Changes in short-term debt	374	178
Retirement of long-term debt	(125)	(450)
Dividends paid on common stock	(110)	(85)
Other financing activities	—	(3)
Net cash flows provided by (used in) financing activities	139	(360)
Decrease in cash and cash equivalents	(51)	(205)
Cash and cash equivalents at beginning of period	144	234
Cash and cash equivalents at end of period	$ 93	$ 29

See the Combined Notes to Consolidated Financial Statements

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 93	$ 144
Restricted cash	3	—
Accounts receivable, net		
Customer	455	539
Other	518	452
Inventories, net	102	91
Deferred income taxes	32	83
Counterparty collateral deposited	8	53
Regulatory assets	274	388
Other	26	25
Total current assets	1,511	1,775
Property, plant and equipment, net	14,233	13,826
Deferred debits and other assets		
Regulatory assets	732	666
Investments	6	8
Investments in affiliates	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,244	2,039
Prepaid pension asset	1,680	1,661
Other	312	299
Total deferred debits and other assets	7,605	7,304
Total assets	$ 23,349	$ 22,905

See the Combined Notes to Consolidated Financial Statements

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 374	$ —
Long-term debt due within one year	744	252
Accounts payable	432	379
Accrued expenses	253	295
Payables to affiliates	70	97
Customer deposits	135	136
Regulatory liabilities	151	170
Mark-to-market derivative liability	16	18
Mark-to-market derivative liability with affiliate	—	226
Other	81	82
Total current liabilities	2,256	1,655
Long-term debt	4,707	5,315
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,997	4,272
Asset retirement obligations	100	99
Non-pension postretirement benefits obligations	327	273
Regulatory liabilities	3,276	3,229
Mark-to-market derivative liability	69	49
Other	1,010	484
Total deferred credits and other liabilities	8,779	8,406
Total liabilities	15,948	15,582
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	5,188	5,014
Retained earnings	625	721
Total shareholders' equity	7,401	7,323
Total liabilities and shareholders' equity	$ 23,349	$ 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	—	—	14	—	—	14
Appropriation of retained earnings for future dividends	—	—	(14)	14	—	—
Common stock dividends	—	—	—	(110)	—	(110)
Parent tax matter indemnification	—	174	—	—	—	174
Balance, June 30, 2013	$ 1,588	$ 5,188	$ (1,639)	$ 2,264	$ —	$ 7,401

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Operating revenues				
Operating revenues	$ 672	$ 714	$1,567	$1,588
Operating revenues from affiliates	—	1	—	2
Total operating revenues	672	715	1,567	1,590
Operating expenses				
Purchased power and fuel	161	171	426	472
Purchased power from affiliate	97	125	238	235
Operating and maintenance	155	146	319	318
Operating and maintenance from affiliates	26	26	50	57
Depreciation and amortization	56	54	113	107
Taxes other than income	39	42	80	74
Total operating expenses	534	564	1,226	1,263
Operating income	138	151	341	327
Other income and (deductions)				
Interest expense	(25)	(28)	(51)	(56)
Interest expense to affiliates, net	(3)	(3)	(6)	(6)
Other, net	—	2	3	5
Total other income and (deductions)	(28)	(29)	(54)	(57)
Income before income taxes	110	122	287	270
Income taxes	32	42	87	93
Net income	78	80	200	177
Preferred security dividends and redemption	6	1	7	2
Net income attributable to common shareholder	72	79	193	175
Comprehensive income, net of income taxes				
Net income	78	80	200	177
Other comprehensive income, net of income taxes				
Change in unrealized gains on marketable securities	—	—	—	1
Other comprehensive income	—	—	—	1
Comprehensive income	$ 78	$ 80	$ 200	$ 178

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Six Months Ended June 30, 2013	2012
Cash flows from operating activities		
Net income	$ 200	$ 177
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	113	107
Deferred income taxes and amortization of investment tax credits	25	19
Other non-cash operating activities	50	66
Changes in assets and liabilities:		
Accounts receivable	55	62
Receivables from and payables to affiliates, net	(18)	9
Inventories	27	26
Accounts payable, accrued expenses and other current liabilities	35	(83)
Income taxes	39	121
Pension and non-pension postretirement benefit contributions	(10)	(8)
Other assets and liabilities	(49)	(87)
Net cash flows provided by operating activities	467	409
Cash flows from investing activities		
Capital expenditures	(254)	(179)
Changes in intercompany money pool	(263)	18
Change in restricted cash	(1)	(3)
Other investing activities	4	7
Net cash flows used in investing activities	(514)	(157)
Cash flows from financing activities		
Dividends paid on common stock	(166)	(172)
Dividends paid on preferred securities	(1)	(2)
Redemption of preferred securities	(93)	—
Other financing activities	1	—
Net cash flows used in financing activities	(259)	(174)
Increase (decrease) in cash and cash equivalents	(306)	78
Cash and cash equivalents at beginning of period	362	194
Cash and cash equivalents at end of period	$ 56	$ 272

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 56	$ 362
Restricted cash and cash equivalents	1	—
Accounts receivable, net ($286 and $289 gross accounts receivable pledged as collateral as of June 30, 2013 and December 31, 2012, respectively)		
Customer	286	364
Other	141	161
Inventories, net		
Fossil fuel	36	65
Materials and supplies	20	19
Deferred income taxes	42	40
Receivable from Exelon intercompany money pool	263	—
Prepaid utility taxes	71	21
Regulatory assets	35	32
Other	43	30
Total current assets	994	1,094
Property, plant and equipment, net	6,207	6,078
Deferred debits and other assets		
Regulatory assets	1,400	1,378
Investments	23	22
Investments in affiliates	8	8
Receivable from affiliates	366	360
Prepaid pension asset	373	373
Other	36	40
Total deferred debits and other assets	2,206	2,181
Total assets	$ 9,407	$ 9,353

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term notes payable — accounts receivable agreement	$ 210	$ 210
Long-term debt due within one year	300	300
Accounts payable	264	244
Accrued expenses	107	82
Payables to affiliates	60	76
Customer deposits	48	51
Regulatory liabilities	166	169
Other	34	26
Total current liabilities	1,189	1,158
Long-term debt	1,648	1,647
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,397	2,331
Asset retirement obligations	30	29
Non-pension postretirement benefits obligations	295	284
Regulatory liabilities	547	538
Other	108	113
Total deferred credits and other liabilities	3,377	3,295
Total liabilities	6,398	6,284
Commitments and contingencies		
Preferred securities	—	87
Shareholder's equity		
Common stock	2,388	2,388
Retained earnings	620	593
Accumulated other comprehensive income, net	1	1
Total shareholder's equity	3,009	2,982
Total liabilities and shareholders' equity	$ 9,407	$ 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	—	200	—	200
Common stock dividends	—	(166)	—	(166)
Preferred security dividends	—	(1)	—	(1)
Redemption of preferred securities	—	(6)	—	(6)
Balance, June 30, 2013	$ 2,388	$ 620	$ 1	$ 3,009

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

(In millions)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Operating revenues				
Operating revenues	$ 649	$ 614	$ 1,525	$ 1,307
Operating revenues from affiliates	4	2	8	5
Total operating revenues	653	616	1,533	1,312
Operating expenses				
Purchased power and fuel	189	201	501	494
Purchased power from affiliate	99	84	212	176
Operating and maintenance	139	136	266	297
Operating and maintenance from affiliates	21	25	37	59
Depreciation and amortization	82	71	175	150
Taxes other than income	54	47	109	95
Total operating expenses	584	564	1,300	1,271
Operating income	69	52	233	41
Other income and (deductions)				
Interest expense	(32)	(34)	(66)	(75)
Other, net	4	7	9	13
Total other income and (deductions)	(28)	(27)	(57)	(62)
Income (loss) before income taxes	41	25	176	(21)
Income taxes	16	9	70	(7)
Net income (loss)	25	16	106	(14)
Preference stock dividends	3	3	6	6
Net income (loss) attributable to common shareholder	$ 22	$ 13	$ 100	$ (20)
Comprehensive income (loss)	$ 25	$ 16	$ 106	$ (14)

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

(In millions)	Six Months Ended June 30, 2013	2012
Cash flows from operating activities		
Net (loss) income	$ 106	$ (14)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	175	150
Deferred income taxes and amortization of investment tax credits	98	91
Other non-cash operating activities	61	100
Changes in assets and liabilities:		
Accounts receivable	(58)	76
Receivables from and payables to affiliates, net	(11)	(3)
Inventories	4	37
Accounts payable, accrued expenses and other current liabilities	(28)	(71)
Income taxes	(33)	(48)
Pension and non-pension postretirement benefit contributions	(11)	(8)
Other assets and liabilities	63	43
Net cash flows provided by operating activities	366	353
Cash flows from investing activities		
Capital expenditures	(264)	(266)
Change in restricted cash	3	8
Other investing activities	4	(10)
Net cash flows used in investing activities	(257)	(268)
Cash flows from financing activities		
Issuance of long-term debt	300	—
Repayment of long-term debt	(33)	(141)
Dividends paid on preference stock	(6)	(6)
Contributions from parent	—	66
Other financing activities	(2)	—
Net cash flows provided by (used in) financing activities	259	(81)
Increase in cash and cash equivalents	368	4
Cash and cash equivalents at beginning of period	89	49
Cash and cash equivalents at end of period	$ 457	$ 53

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 457	$ 89
Restricted cash and cash equivalents of variable interest entity	27	30
Accounts receivable, net		
Customer	415	409
Other	145	111
Income taxes receivable	30	3
Inventories, net		
Gas held in storage	44	51
Materials and supplies	34	31
Deferred income taxes	13	1
Prepaid utility taxes	1	57
Regulatory assets	142	190
Other	6	8
Total current assets	1,314	980
Property, plant and equipment, net	5,637	5,498
Deferred debits and other assets		
Regulatory assets	536	522
Investments	5	5
Investments in affiliates	8	8
Prepaid pension asset	445	467
Other	23	26
Total deferred debits and other assets	1,017	1,028
Total assets	$ 7,968	$ 7,506

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long-term debt due within one year	$ 400	$ 400
Long-term debt of variable interest entity due within one year	68	67
Accounts payable	138	195
Accrued expenses	105	106
Deferred income taxes	9	—
Payables to affiliates	59	65
Customer deposits	69	71
Regulatory liabilities	40	29
Other	60	47
Total current liabilities	948	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	1,761	1,658
Asset retirement obligations	7	8
Non-pension postretirement benefits obligations	223	229
Regulatory liabilities	221	214
Other	116	90
Total deferred credits and other liabilities	2,328	2,199
Total liabilities	5,510	5,148
Commitments and contingencies		
Shareholders' equity		
Common stock	1,360	1,360
Retained earnings	908	808
Total shareholder's equity	2,268	2,168
Preference stock not subject to mandatory redemption	190	190
Total equity	2,458	2,358
Total liabilities and shareholders' equity	$ 7,968	$ 7,506

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

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2012	$ 1,360	$ 808	$ 2,168	$ 190	$2,358
Net income	—	106	106	—	106
Preference stock dividends	—	(6)	(6)	—	(6)
Balance, June 30, 2013	$ 1,360	$ 908	$ 2,268	$ 190	$2,458

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 six months ended June 30, 2013 and 2012 and the financial position as of June 30, 2013 and December 31, 2012. However, for Exelon's financial reporting, Exelon is reporting BGE activity for the three and six months ended June 30, 2013 and from March 12, 2012 through June 30, 2012 and the financial position as of June 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 six months ended June 30, 2013, BGE recorded a $2 million correcting adjustment to decrease amortization expense related to regulatory assets that was originally recorded during 2012. Exelon and BGE have concluded that this correcting adjustment is not material to their respective results of operations or cash flows for the six months ended June 30, 2013 or any prior period. Exelon and BGE do not expect this correcting adjustment 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 June 30, 2013 and 2012 and for the three and six months then ended are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants' respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2012 Consolidated Balance Sheets were obtained from audited financial statements. Certain prior year amounts in 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. The reclassifications did not materially affect any of the Registrants' net income or cash flows from operating 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 the Registrants during the period.

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 settle 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.

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 is 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.

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 is 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 is 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.

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 June 30, 2013 and December 31, 2012, the Registrants' consolidated five VIEs or VIE groups for which the Registrants were the primary beneficiary, and the Registrants had significant interests in eight other VIEs for which the Registrants do not have the power to direct the entities' activities and, accordingly, were not the primary beneficiary.

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;
- a retail power supply company;

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 June 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 six months ended June 30, 2013, BGE remitted $17 million and $39 million, respectively, to BondCo. During the three and six months ended June 30, 2012, BGE remitted $15 million and $35 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 six months ended June 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, Generation, and BGE's consolidated financial statements at June 30, 2013 and December 31, 2012 are as follows:

	June 30, 2013			December 31, 2012		
	Exelon(a)(b)	Generation(b)	BGE	Exelon(a)(b)	Generation(b)	BGE
Current assets	$ 462	$ 426	$ 27	$ 550	$ 519	$ 30
Noncurrent assets	1,961	1,938	—	1,802	1,762	—
Total assets	$ 2,423	$ 2,364	$ 27	$ 2,352	$ 2,281	$ 30
Current liabilities	$ 474	$ 391	$ 73	$ 685	$ 613	$ 71
Noncurrent liabilities	981	728	230	837	532	265
Total liabilities	$ 1,455	$ 1,119	$303	$ 1,522	$ 1,145	$336

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Includes total assets of $115 million and total liabilities of $57 million as of June 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.

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, or provided liquidity arrangements, performance guarantees or other commitments associated with these commercial agreements.

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

The Registrants' unconsolidated VIEs consist of:

- Energy purchase and sale agreements with VIEs for which Generation has concluded that consolidation is not required.
- ZionSolutions, LLC asset sale agreement with EnergySolutions, Inc. and certain subsidiaries in which Generation has a variable interest but has concluded that consolidation is not required.
- 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 June 30, 2013 and December 31, 2012, Exelon and Generation did have significant variable interests in eight and nine, respectively, VIEs for which they were not the primary beneficiary; including certain equity method investments and certain commercial agreements. The following tables present summary information about the significant unconsolidated VIE entities:

June 30, 2013	Commercial Agreement VIEs	Equity Method Investment VIEs	Total
Total assets(a)	$ 202	$ 348	$550
Total liabilities(a)	83	108	191
Registrants' ownership interest(a)	—	97	97
Other ownership interests(a)	119	143	262
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	78	78
Contract intangible asset	8	—	8
Debt and payment guarantees	—	5	5
Net assets pledged for Zion Station decommissioning(b)	47	—	47

(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 Generation's and Exelon'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 $538 million and $614 million as of June 30, 2013 and December 31, 2012, respectively; offset by payables to ZionSolutions LLC of $491 million and $564 million as of June 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 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 were 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.

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 financing for the construction of the building. Once the financing conditions are met, construction will commence and the building is expected to be ready for occupancy within 2 years. 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 June 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, the total commitment under the contract is $89 million and achievement of commercial operation is expected in 2015.

The settlement agreement 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 June 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 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.

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

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 six months ended June 30, 2013 amounted to $162 million and $332 million, respectively. Exelon's and Generation's amortization expense for the three months ended June 30, 2012 and for the period March 12, 2012 to June 30, 2012 amounted to $370 million and $501 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 $38 million for the three and six months ended June 30, 2013, respectively, and $9 million and $12 million for the three months ended June 30, 2012 and for the period March 12, 2012 to June 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. The weighted-average amortization period is approximately 1.5 years.

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

Exelon's and Generation's amortization expense for the fair value of the Constellation trade name intangible asset for the three and six months ended June 30, 2013 amounted to $6 million and $12 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 June 30, 2012 and the period March 12, 2012 to June 30, 2012 amounted to $6 million and $8 million, respectively. The amortization period is approximately 10 years. 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 averaging approximately 12.4 years. Exelon's and Generation's straight line amortization expense for the three and six months ended June 30, 2013 amounted to $4 million and $9 million, respectively. Exelon's and Generation's straight line amortization expense for the three months ended June 30, 2012 and the period March 12, 2012 to June 30, 2012 amounted to $6 million and $7 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 June 30, 2013:

					Estimated amortization expense					
Description	Weighted Average Amortization (Years)	Gross	Accumulated Amortization	Net	Remainder of 2013	2014	2015	2016	2017	2018 and Beyond
Unamortized energy contracts, net(a)	1.5	$1,499	$ (1,279)	$220	$ 99	$ 75	$18	$(30)	$(21)	$ 79
Trade name	10.0	243	(32)	211	12	24	24	24	24	103
Retail relationships	12.4	214	(23)	191	10	19	19	19	19	105
Total, net		$1,956	$ (1,334)	$622	$ 121	$118	$61	$ 13	$ 22	$ 287

(a) Includes the fair value of BGE's power and gas supply contracts of $52 million for which an offsetting regulatory asset was also recorded.

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 six months ended June 30, 2013 and 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 $653 million and net income of $25 million during the three months ended June 30, 2013, and operating revenues of $1,533 million and net income of $106 million during the six months ended June 30, 2013.

The impact of BGE on Exelon's Consolidated Statement of Operations and Comprehensive Income included operating revenues of $616 million and net income of $16 million during the three months ended June 30, 2012, and operating revenues of $668 million and net loss of $49 million during the six months ended June 30, 2012.

During the three months ended June 30, 2013, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $30 million, $20 million, $5 million, $2 million and $1 million, respectively. During the six months ended June 30, 2013, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $63 million, $43 million, $9 million, $5 million and $3 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $10 million, $8 million and $2 million as a regulatory asset as of June 30, 2013. Additionally, Exelon and BGE established a regulatory asset of $6 million as of June 30, 2013 for previously incurred 2012 merger and integration-related costs.

During the three months ended June 30, 2012, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $119 million, $94 million, $8 million, $4 million and $2 million, respectively. During the six months ended June 30, 2012, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $635 million, $204 million, $26 million, $11 million and $171 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $41 million, $23 million and $18 million as a regulatory asset as of June 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 six months ended June 30, 2012.

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.

There was no severance expense associated with the post-merger integration recognized for the three months ended June 30, 2013 for Exelon, Generation, ComEd, PECO and BGE. The amount of severance expense associated with the post-merger integration recognized for the six months ended June 30, 2013 for Exelon, Generation, ComEd, PECO and BGE were $3 million, $3 million, $0 million, $0 million and $0 million, respectively. For Generation, the $3 million represents amounts billed by BSC through intercompany allocations. Estimated costs to be incurred after June 30, 2013 are not material.

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

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For the three and six months ended June 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 June 30, 2012 Severance Benefits(a)	Exelon	Generation	ComEd(b)	PECO	BGE(c)
Severance charges	$ 42	$ 29	$ 6	$ 4	$ 3
Stock compensation	(5)	(3)	(1)	(1)	(1)
Other charges(d)	(1)	(1)	—	(1)	—
Total severance benefits	$ 36	$ 25	$ 5	$ 2	$ 2

Six Months Ended June 30, 2012 Severance Benefits(a)	Exelon	Generation	ComEd(b)	PECO	BGE(c)
Severance charges	$ 109	$ 64	$ 15	$ 7	$ 17
Stock compensation	3	2	—	—	—
Other charges(d)	7	4	1	—	1
Total severance benefits	$ 119	$ 70	$ 16	$ 7	$ 18

(a) The amounts above include $10 million and $40 million at Generation, $3 million and $14 million at ComEd, $2 million and $7 million at PECO, and $1 million and $6 million at BGE, for amounts billed by BSC through intercompany allocations for the three and six months ended June 30, 2012, respectively.
(b) ComEd established regulatory assets of $5 million and $16 million for severance benefits costs for the three and six months ended June 30, 2012, respectively. The majority of these costs are expected to be recovered over a five-year period.
(c) BGE established regulatory assets of $2 million and $18 million for severance benefits costs for the three and six months ended June 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:

Six Months Ended June 30, 2013 Severance liability	Exelon	Generation	ComEd	PECO	BGE
Balance at December 31, 2012	$ 111	$ 33	$ 1	$ —	$ 11
Severance charges(a)	2	—	—	—	—
Stock compensation	1	—	—	—	—
Payments	(37)	(13)	—	—	(3)
Balance at June 30, 2013	$ 77	$ 20	$ 1	$ —	$ 8

(a) Includes salary continuance and health and welfare severance benefits. Amounts represent ongoing severance plan benefits. Amounts also include one-time termination benefits of $1 million for Exelon as of June 30, 2013.

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)

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 June 30, 2012	
	Generation	Exelon
Total Revenues	$ 4,051	$ 6,256
Net income attributable to Exelon	397	528
Basic Earnings Per Share	n.a.	$ 0.62
Diluted Earnings Per Share	n.a.	0.62

	Six Months Ended June 30, 2012	
	Generation	Exelon
Total Revenues	$ 8,523	$13,284
Net income attributable to Exelon	567	979
Basic Earnings Per Share	n.a.	$ 1.26
Diluted Earnings Per Share	n.a.	1.25

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 June 30, 2013, and December 31, 2012, ComEd had recorded a net regulatory asset associated with the distribution formula rate of $329 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. The enactment of Senate Bill 9 resulted in increased operating revenue of $10 million for the three and six months ended June 30, 2013. ComEd projects the override of Senate Bill 9 will result in increased operating revenues of approximately $15 million for the remainder of 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 structure to reflect the impacts of Senate Bill 9. On June 5, 2013, the ICC approved the May 30 filing implementing ComEd's formula 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.

In addition, 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 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 in the filing is based on 2012 actual costs and projected 2013 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2012 to the actual costs incurred for that year. ComEd requested a total increase to the revenue requirement including the impacts of Senate Bill 9, of $359 million, reflecting an increase of $165 million for the initial revenue requirement for 2013 and an increase of $194 million for the annual reconciliation for 2012. The revenue requirement provides for a weighted average debt and equity return on distribution rate base of 6.91% 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 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 will begin 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.

2010 Illinois Electric Distribution Rate Case (Exelon and ComEd). On June 30, 2010, ComEd filed its 2010 electric distribution rate case (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 Illinois Appellate Court's ruling in ComEd's 2007 electric distribution rate case (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 Illinois Appellate Court by several parties on a number of issues. On May 16, 2013, the Illinois Appellate 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 alternative energy 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 an alternative electric generation supplier. On January 22, 2013, ComEd filed an application for rehearing, requesting the ICC reconsider its December 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 on February 22, 2013, questioning the legality of requiring ComEd to procure power for its non-eligible retail customers. 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.

Pennsylvania Regulatory Matters

Pennsylvania Procurement Proceedings (Exelon and PECO). PECO's current PAPUC approved DSP Program, under which PECO is providing default electric service, has 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 will procure electric supply for its default electric customers through five competitive procurements. The load for the residential and small and medium commercial classes will be served through competitively procured fixed price, full requirements contracts of two years or less. For the large commercial and industrial class load, PECO will competitively procure 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. 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. 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 cost of the original meters (as further described below), on its smart meter infrastructure and approximately $120 million on smart grid investments through 2014 of which $200 million will be funded by SGIG as discussed below. As of June 30, 2013, PECO has spent $312 million and $107 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received to date.

Pursuant to the ARRA of 2009, PECO and the DOE entered into a Financial Assistance Agreement to extend PECO $200 million in non-taxable SGIG funds of which $140 million relates to smart meter deployment and $60 million relates to smart grid infrastructure. As part of the agreement, the DOE has a conditional ownership interest in qualifying Federally-funded project property and equipment, which is subordinate to PECO's existing mortgage. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. As of June 30, 2013, PECO has received $167 million of the $200 million in reimbursements. PECO's outstanding receivable from the DOE for reimbursable costs was $10 million as of June 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 intends to move 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. In November 2012, PECO requested and received approval from the DOE that the original meters continue to be allowable costs. 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 June 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. If PECO later determines that the 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.

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 mid-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 2.9% 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 June 30, 2013 and December 31, 2012, BGE recorded a regulatory asset of $45 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 will hold 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 June 30, 2013, BGE had received $176 million in reimbursements from the DOE. As of June 30, 2013, BGE's outstanding receivable from the DOE for reimbursable costs was $17 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 June 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.

On April 27, 2012, a civil complaint was filed in the United States District Court for the District of Maryland by certain unaffiliated parties that challenges the actions taken by the MDPSC on Federal law grounds. Among other requests for relief, the plaintiffs seek to enjoin the MDPSC from executing or otherwise putting into effect any part of its order. The MDPSC and CPV filed motions to dismiss the Federal lawsuit, which were both denied by the U.S. District Court on August 3, 2012. Trial of this matter occurred in March 2013, and a decision from the trial judge is now pending.

On May 4, 2012, BGE filed a petition in the Circuit Court for Anne Arundel County, Maryland, seeking judicial review of the MDPSC order. 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. The Circuit Court proceeding is currently in the pre-hearing briefing stage, and a hearing before the Circuit Court Judge is scheduled for September 10, 2013.

Depending on the ultimate outcome of the pending 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 related to non-severance merger integration costs, which is $8 million as of June 30, 2013 and includes $6 million of costs incurred during 2012. Current Maryland PSC 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 that requires BGE and other Maryland utilities to file several comprehensive reports with short-term and long-term plans to improving reliability and grid resiliency that are 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. BGE 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 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. The new electric and gas distribution base rates are expected to take effect in December 2013. BGE 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.

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 authorized 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 and updated by FERC's November 2007 order in BGE's 2007 incentive rate filing, the base rate of return on common equity for BGE's electric transmission business is 11.3%.

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 June 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 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 the implementation of its standard offer service programs in Maryland should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on BGE’s results of operations, cash flows or financial position.

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.

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 Third Circuit Court of Appeals. 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 auctions take place 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 District 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. In the third quarter of 2013, Exelon expects to file a water quality certification application pursuant to Section 401 of the Clean Water Act with the MDE for Conowingo, and a water quality certification application pursuant to Section 401 of the Clean Water Act with the PA DEP for Muddy Run, addressing these and other issues. 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,

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

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.

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

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

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO and BGE as of June 30, 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.

June 30, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits(a)	$ 308	$ 3,622	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	14	1,409	5	64	—	1,279	9	66
AMI programs	4	99	4	22	—	32	—	45
AMI meter events	—	17	—	—	—	17	—	—
Under-recovered distribution service costs	84	245	84	245	—	—	—	—
Debt costs	12	63	9	58	3	5	1	9
Fair value of BGE long-term debt(b)	—	233	—	—	—	—	—	—
Fair value of BGE supply contract(c)	46	6	—	—	—	—	—	—
Severance	29	14	25	—	—	—	4	14
Asset retirement obligations	—	93	—	68	—	25	—	—
MGP remediation costs	49	215	42	184	6	30	1	1
RTO start-up costs	2	1	2	1	—	—	—	—
Under-recovered electric universal service fund costs	3	—	—	—	3	—	—	—
Renewable energy and associated RECs	16	69	16	69	—	—	—	—
Under-recovered energy and transmission costs	71	—	71	—	—	—	—	—
DSP Program costs	—	3	—	—	—	3	—	—
DSP II Program costs	2	1	—	—	2	1	—	—
Deferred storm costs	3	4	—	—	—	—	3	4
Electric generation-related regulatory asset	13	37	—	—	—	—	13	37
Rate stabilization deferral	68	194	—	—	—	—	68	194
Energy efficiency and demand response programs	42	152	—	—	—	—	42	152
Merger integration costs(d)	1	10	—	—	—	—	1	10
Other	37	32	16	21	21	8	—	4
Total regulatory assets	$ 804	6,519	$ 274	$ 732	$ 35	$ 1,400	$ 142	$ 536

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

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June 30, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Nuclear decommissioning	$ —	$ 2,434	$ —	$ 2,068	$ —	$ 366	$ —	$ —
Removal costs	99	1,422	78	1,201	—	—	21	221
Energy efficiency and demand response programs	98	—	31	—	67	—	—	—
DLC Program Costs	1	11	—	—	1	11	—	—
Energy efficiency Phase 2	—	7	—	—	—	7	—	—
Electric distribution tax repairs	20	121	—	—	20	121	—	—
Gas distribution tax repairs	8	42			8	42		
Over-recovered energy and transmission costs	78	4	2	4	66(e)	—	10(i)	—
Over-recovered gas universal service fund costs	3	—	—	—	3	—	—	—
Revenue subject to refund(f)	40	—	40	—	—	—	—	—
Over-recovered electric and gas revenue decoupling(g)	8	—	—	—	—	—	8	—
Other	2	3	—	3	1	—	1	—
Total regulatory liabilities	$ 357	$ 4,044	$ 151	$ 3,276	$ 166	$ 547	$ 40	$ 221

December 31, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits(a)	$ 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(b)	—	256	—	—	—	—	—	—
Fair value of BGE supply contract(c)	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	—	—	—	—
Under-recovered energy and transmission costs	43	—	14	—	1(h)	—	28(i)	—
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(g)	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	—	—	—	—	—
Over-recovered energy and transmission costs	54	—	6	—	48(e)	—	—	—
Over-recovered gas universal service fund costs	3	—	—	—	3	—	—	—
Over-recovered AEPS costs	2	—	—	—	2	—	—	—
Revenue subject to refund(f)	40	—	40	—	—	—	—	—
Over-recovered gas revenue decoupling(g)	7	—	—	—	—	—	7	—
Total regulatory liabilities	$ 368	$ 3,981	$ 170	$ 3,229	$ 169	$ 538	$ 29	$ 214

(a) Pension and other postretirement benefit regulatory assets include a regulatory asset established at the date of the merger related to BGE's portion of the deferred costs associated with legacy Constellation's pension and other postretirement benefit plans. That BGE-related regulatory asset is being amortized over a period of approximately 12 years, which generally represents the expected average remaining service period of plan participants at the date of the merger

(b) 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.

(c) 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.

(d) ReIates to integration costs to achieve distribution synergies related to the merger transaction.

(e) Includes $35 million related to the over-recovered electric supply costs under the GSA, $24 million related to the over-recovered natural gas costs under the PGC and $7 million related to over-recovered electric transmission costs as of June 30, 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.

(f) Primarily represents the regulatory liability for revenue subject to refund recorded pursuant to the ICC's order in the 2007 Rate Case. See Note 3 of Exelon's 2012 Form 10-K for additional information regarding the 2007 Rate Case.

(g) Represents the electric and gas distribution costs recoverable from or refundable to customers under BGE's decoupling mechanism. As of June 30, 2013, includes $1 million of under-recovered electric distribution costs and $9 million of over-recovered gas distribution costs under BGE's decoupling mechanism. As of December 31, 2012, relates to $5 million of under-recovered electric distribution costs and $7 million of over-recovered gas distribution costs under BGE's decoupling mechanism.

(h) Relates to under-recovered transmission costs.

(i) Relates to $7 million of over-recovered natural gas supply costs and to $3 million of over-recovered natural electric supply costs as of June 30, 2013. As of December 31, 2012, includes to $9 million of under-recovered electric supply costs and $19 million of under-recovered natural gas supply costs.

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

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

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

As of June 30, 2013	Exelon	ComEd	PECO	BGE
Purchased receivables(a)	$ 230	$ 87	$ 70	$ 73
Allowance for uncollectible accounts(b)	(24)	(13)	(6)	(5)
Purchased receivables, net	$ 206	$ 74	$ 64	$ 68

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 June 30, 2013	Three Months Ended June 30, 2012
Equity investment income	$ 11	$ 4
Amortization of basis difference in CENG	(30)	(62)
Total equity in losses — CENG	$ (19)	$ (58)

	Six Months Ended June 30, 2013	For the Period March 12, through June 30, 2012
Equity investment income (loss)	$ 26	$ (5)
Amortization of basis difference in CENG	(57)	(74)
Total equity in losses — CENG	$ (31)	$ (79)

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 June 30, 2013	Income/(Expense) Six Months Ended June 30, 2013	Income Statement Classification	Accounts Receivable/ (Accounts Payable) At June 30, 2013
PPA	$ (231)	$ (479)	Purchased power and fuel	$ (91)
PSAA	1	2	Operating revenues	—
SSA	11	22	Operating revenues	4

Agreement	Income/(Expense) Three Months Ended June 30, 2012	Income/(Expense) For the Period March 12 through June 30, 2012	Income Statement Classification	Accounts Receivable/ (Accounts Payable) At June 30, 2012
PPA	$ (216)	$ (251)	Purchased power and fuel	$ (90)
PSAA	2	2	Operating revenues	—
SSA	12	15	Operating revenues	4

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

On July 29, 2013, Exelon, Generation and subsidiaries of Generation entered into a Master Agreement with Electricité de France, S.A. (EDF), EDF Inc. (EDFI), a subsidiary of EDF, CENG, and subsidiaries of 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.

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 Generation accounts for its investment in CENG under the equity method of accounting. The execution of the agreements described above at the closing could result in Generation being required to consolidate the financial position and results of operations of CENG following the closing. If that accounting change were to occur, Generation would be required to re-measure its investment in CENG to fair value, with any difference between the carrying value and fair value at that date recognized as a gain or loss, which could be material to Generation's and Exelon's results of operations.

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

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.

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 impairment charge during the second quarter of 2013, which was recorded in Investments and Operating and maintenance in the Consolidated Balance

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

	June 30, 2013	December 31, 2012
Estimated residual value of leased assets	$1,465	$ 1,492
Less: unearned income	782	807
Net investment in long-term leases	$ 683	$ 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.

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.

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

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 June 30, 2013 and December 31, 2012:

Exelon

	June 30, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 875	$ 3	$ 872	$ —	$ 875
Long-term debt (including amounts due within one year)	18,601	—	18,926	461	19,387
Long-term debt to financing trusts	648	—	—	650	650
SNF obligation	1,020	—	777	—	777

	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

Generation

	June 30, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 288	$ —	$ 288	$ —	$ 288
Long-term debt (including amounts due within one year)	7,213	—	6,817	443	7,260
SNF obligation	1,020	—	777	—	777

	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

	June 30, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 374	$ —	$ 374	$ —	$ 374
Long-term debt (including amounts due within one year)	5,451	—	6,033	18	6,051
Long-term debt to financing trust	206	—	—	210	210

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

	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

	June 30, 2013				
	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)	1,948	—	2,122	—	2,122
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

BGE

	June 30, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 3	$ 3	$ —	$ —	$ 3
Long-term debt (including amounts due within one year)	2,444	—	2,598	—	2,598
Long-term debt to financing trusts	258	—	—	257	257

	December 31, 2012				
	Carrying Amount	Fair Value			
		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.

Generation has fixed rate project financing debt (Level 3), the fair value of which 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, for certain government-backed debt, 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, 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, non-exchange-based derivatives, commingled and mutual investment funds priced at NAV per fund share and fair value hedges.

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

- 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 non-exchange-based derivatives, investments priced using an alternative pricing mechanism, and middle market lending using third party valuations.

There were no transfers between Level 1 and Level 2 during the six months ended June 30, 2013.

Exelon

The following tables present assets and liabilities measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2013 and December 31, 2012:

As of June 30, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 589	$ —	$ —	$ 589
Nuclear decommissioning trust fund investments				
Cash equivalents	229	—	—	229
Equity				
Individually held	1,691	—	—	1,691
Commingled funds	—	2,071	—	2,071
Equity funds subtotal	1,691	2,071	—	3,762
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	966	—	—	966
Debt securities issued by states of the United States and political subdivisions of the states	—	314	—	314
Debt securities issued by foreign governments	—	85	—	85
Corporate debt securities	—	1,727	—	1,727
Federal agency mortgage-backed securities	—	18	—	18
Commercial mortgage-backed securities (non-agency)	—	41	—	41
Residential mortgage-backed securities (non-agency)	—	10	—	10
Mutual funds	—	37	—	37
Fixed income subtotal	966	2,232	—	3,198
Middle market lending	—	—	240	240
Other debt obligations	—	12	—	12
Nuclear decommissioning trust fund investments subtotal(b)	2,886	4,315	240	7,441
Pledged assets for Zion Station decommissioning				
Cash equivalents	—	62	—	62
Equity				
Individually held	1	—	—	1
Equity funds subtotal	1	—	—	1

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

As of June 30, 2013	Level 1	Level 2	Level 3	Total
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	143	8	—	151
Debt securities issued by states of the United States and political subdivisions of the states	—	27	—	27
Corporate debt securities	—	193	—	193
Federal agency mortgage-backed securities	—	17	—	17
Commercial mortgage-backed securities (non-agency)	—	1	—	1
Fixed income subtotal	143	246	—	389
Middle market lending	—	—	111	111
Other debt obligations	—	3	—	3
Pledged assets for Zion Station decommissioning subtotal(c)	144	311	111	566
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds(d)(e)	67	—	—	67
Rabbi trust investments subtotal	69	—	—	69
Commodity mark-to-market derivative assets				
Economic hedges	721	2,659	676	4,056
Proprietary trading	839	1,445	162	2,446
Effect of netting and allocation of collateral(f)	(1,645)	(3,087)	(226)	(4,958)
Commodity mark-to-market assets subtotal	(85)	1,017	612	1,544
Interest rate mark-to-market derivative assets	36	74	—	110
Effect of netting and allocation of collateral	(36)	(1)	—	(37)
Interest rate mark-to-market derivative assets subtotal	—	73	—	73
Other investments	1	—	11	12
Total assets	3,604	5,716	974	10,294
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(977)	(1,974)	(276)	(3,227)
Proprietary trading	(855)	(1,371)	(141)	(2,367)
Effect of netting and allocation of collateral(f)	1,833	3,217	236	5,286
Commodity mark-to-market liabilities subtotal(h)	1	(128)	(181)	(308)
Interest rate mark-to-market derivative liabilities	(36)	(18)	—	(54)
Effect of netting and allocation of collateral	36	1	—	37
Interest rate mark-to-market derivative liabilities subtotal	—	(17)	—	(17)
Deferred compensation obligation	—	(105)	—	(105)
Total liabilities	1	(250)	(181)	(430)
Total net assets	$ 3,605	$ 5,466	$ 793	$ 9,864

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 mark-to-market derivative assets				
Cash flow hedges	—	—	—	—
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 mark-to-market assets subtotal(g)	80	1,076	656	1,812
Interest rate mark-to-market derivative assets	—	114	—	114
Effect of netting and allocation of collateral	—	(51)	—	(51)
Interest rate mark-to-market derivative assets subtotal	—	63	—	63
Other Investments	2	—	17	19
Total assets	4,062	5,778	945	10,785
Liabilities				
Commodity mark-to-market 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 mark-to-market liabilities subtotal(g)(h)	(83)	(228)	(289)	(600)
Interest rate mark-to-market derivative liabilities	—	(84)	—	(84)
Effect of netting and allocation of collateral	—	51	—	51
Interest rate mark-to-market 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 $22 million and $30 million at June 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 (liabilities) assets of $(28) million and $7 million at June 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.
(d) The mutual funds held by the Rabbi trusts include $51 million related to deferred compensation and $16 million related to Supplemental Executive Retirement Plan at June 30, 2013, and $53 million related to deferred compensation and $16 million related to Supplemental Executive Retirement Plan at December 31, 2012. These funds are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.
(e) Excludes $29 million and $28 million of the cash surrender value of life insurance investments at June 30, 2013 and December 31, 2012, respectively.
(f) Includes collateral postings (received) from counterparties. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $188 million, $130 million and $10 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of June 30, 2013. Collateral (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 $69 million at June 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 six months ended June 30, 2013 and 2012:

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

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

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

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

Three Months Ended June 30, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of March 31, 2012	$ 13	$ 42	$ 359	$ 14	$428
Total realized / unrealized gains (losses)					
Included in net income	—	—	(64)(a)	—	(64)
Included in other comprehensive income	—	—	—	—	—
Included in regulatory assets	—	—	30(b)	—	30
Included in payable for Zion Station decommissioning	—	(1)	—	—	(1)
Change in collateral	—	—	44	—	44
Purchases, sales, issuances and settlements					
Purchases	41	26	—	3	70
Sales	—	(8)	—	—	(8)
Transfers into Level 3	—	—	(34)	—	(34)
Transfers out of Level 3	—	—	(40)	—	(40)
Balance as of June 30, 2012	$ 54	$ 59	$ 295	$ 17	$425
The amount of total gains included in income attributed to the change in unrealized losses related to assets and liabilities held for the three months ended June 30, 2012	$ —	$ —	$ 2	$ —	$ 2

Six Months Ended June 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	—	—	19(a)	—	19
Included in other comprehensive income	—	—	—	—	—
Included in regulatory assets	—	—	(5)(b)	—	(5)
Included in payable for Zion Station decommissioning	—	(1)	—	—	(1)
Change in collateral	—	—	8	—	8
Purchases, sales, issuances and settlements					
Purchases	41	32	329(c)	17	419
Sales	—	(9)	—	—	(9)
Transfers into Level 3	—	—	(34)	—	(34)
Transfers out of Level 3	—	—	(39)	—	(39)
Balance as of June 30, 2012	$ 54	$ 59	$ 295	$ 17	$425
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the six months ended June 30, 2012	$ —	$ —	$ 104	$ —	$104

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

(a) Includes the reclassification of $66 million and $85 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and six months ended June 30, 2012, respectively.
(b) Excludes $14 million and $121 million of decreases in fair value and $161 million and $308 million of realized losses due to settlements for the three and six months ended June 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 six months ended June 30, 2013 and 2012:

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

	Operating Revenue	Purchased Power and Fuel	Other, net
Total gains (losses) included in income for the three months ended June 30, 2012	$ (69)	$ 5	$ —
Total gains (losses) included in income for the six months ended June 30, 2012	$ 23	$ (4)	$ —
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2012	$ 5	$ (3)	$ —
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2012	$ 125	$ (21)	$ —

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

Generation

The following tables present assets and liabilities measured and recorded at fair value on Generation's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2013 and December 31, 2012:

As of June 30, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 45	$ —	$ —	$ 45
Nuclear decommissioning trust fund investments				
Cash equivalents	229	—	—	229
Equity				
Individually held	1,691	—	—	1,691
Commingled funds	—	2,071	—	2,071
Equity funds subtotal	1,691	2,071	—	3,762

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

As of June 30, 2013	Level 1	Level 2	Level 3	Total
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	966	—	—	966
Debt securities issued by states of the United States and political subdivisions of the states	—	314	—	314
Debt securities issued by foreign governments	—	85	—	85
Corporate debt securities	—	1,727	—	1,727
Federal agency mortgage-backed securities	—	18	—	18
Commercial mortgage-backed securities (non-agency)	—	41	—	41
Residential mortgage-backed securities (non-agency)	—	10	—	10
Mutual funds	—	37	—	37
Fixed income subtotal	966	2,232	—	3,198
Middle market lending	—	—	240	240
Other debt obligations	—	12	—	12
Nuclear decommissioning trust fund investments subtotal(b)	2,886	4,315	240	7,441
Pledged assets for Zion Station decommissioning				
Cash equivalents	—	62	—	62
Equity				
Individually held	1	—	—	1
Equity funds subtotal	1	—	—	1
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	143	8	—	151
Debt securities issued by states of the United States and political subdivisions of the states	—	27	—	27
Corporate debt securities	—	193	—	193
Federal agency mortgage-backed securities	—	17	—	17
Commercial mortgage-backed securities (non-agency)	—	1	—	1
Fixed income subtotal	143	246	—	389
Middle market lending	—	—	111	111
Other debt obligations	—	3	—	3
Pledged assets for Zion Station decommissioning subtotal(c)	144	311	111	566
Rabbi trust investments				
Mutual funds(d)(e)	13	—	—	13
Rabbi trust investments subtotal	13	—	—	13
Commodity mark-to-market derivative assets				
Economic hedges	721	2,659	676	4,056
Proprietary trading	839	1,445	162	2,446
Effect of netting and allocation of collateral(f)	(1,645)	(3,087)	(226)	(4,958)
Commodity mark-to-market assets subtotal	(85)	1,017	612	1,544
Interest rate mark-to-market derivative assets	36	42	—	78
Effect of netting and allocation of collateral	(36)	(1)	—	(37)
Interest rate mark-to-market derivative assets subtotal	—	41	—	41
Other investments	1	—	11	12
Total assets	3,004	5,684	974	9,662

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

As of June 30, 2013	Level 1	Level 2	Level 3	Total
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(977)	(1,974)	(191)	(3,142)
Proprietary trading	(855)	(1,371)	(141)	(2,367)
Effect of netting and allocation of collateral(f)	1,833	3,217	236	5,286
Commodity mark-to-market liabilities subtotal	1	(128)	(96)	(223)
Interest rate mark-to-market derivative liabilities	(36)	(18)	—	(54)
Effect of netting and allocation of collateral	36	1	—	37
Interest rate mark-to-market derivative liabilities subtotal	—	(17)	—	(17)
Deferred compensation obligation	—	(25)	—	(25)
Total liabilities	1	(170)	(96)	(265)
Total net assets	$3,005	$ 5,514	$ 878	$ 9,397

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
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

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
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)(e)	13	—	—	13
Rabbi trust investments subtotal	14	—	—	14
Commodity mark-to-market 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(f)	(1,823)	(4,175)	(58)	(6,056)
Commodity mark-to-market assets subtotal(g)	80	1,076	882	2,038
Interest rate mark-to-market derivative assets	—	101	—	101
Effect of netting and allocation of collateral	—	(51)	—	(51)
Interest rate mark-to-market derivative assets subtotal	—	50	—	50
Other investments	2	—	17	19
Total assets	3,497	5,765	1,171	10,433
Liabilities				
Commodity mark-to-market 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(f)	2,042	4,020	25	6,087
Commodity mark-to-market liabilities subtotal	(83)	(228)	(222)	(533)
Interest rate mark-to-market derivative liabilities	—	(84)	—	(84)
Effect of netting and allocation of collateral	—	51	—	51
Interest rate mark-to-market 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

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

(b) Excludes net assets of $22 million and $30 million at June 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.

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

(c) Excludes net (liabilities) assets of $(28) million and $7 million at June 30, 2013 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.
(d) The mutual funds held by the Rabbi trusts are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.
(e) Excludes $9 million and $8 million of the cash surrender value of life insurance investments at June 30, 2013 and December 31, 2012, respectively.
(f) Includes collateral postings (received) from counterparties. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $188 million, $130 million and $10 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of June 30, 2013. Collateral (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 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 six months ended June 30, 2013 and 2012:

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

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

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

(a) Includes the reclassification of $15 million and $73 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and six months ended June 30, 2013, respectively.

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

(c) Includes $10 million which Generation was paid to enter into out of the money purchase contracts.

Three Months Ended June 30, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of March 31, 2012	$ 13	$ 42	$ 1,182	$ 14	$1,251
Total realized / unrealized gains (losses)					
Included in net income	—	—	(69)(a)	—	(69)
Included in other comprehensive income	—	—	(171)(b)	—	(171)
Included in payable for Zion Station decommissioning	—	(1)	—	—	(1)
Changes in collateral	—	—	44	—	44
Purchases, sales, issuances and settlements					
Purchases	41	26	—	3	70
Sales	—	(8)	—	—	(8)
Transfers into Level 3	—	—	(34)	—	(34)
Transfers out of Level 3	—	—	(40)	—	(40)
Balance as of June 30, 2012	$ 54	$ 59	$ 912	$ 17	$1,042
The amount of total gains included in income attributed to the change in unrealized (losses) related to assets and liabilities held for the three months ended June 30, 2012	$ —	$ —	$ (13)	$ —	$ (13)

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

Six Months Ended June 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	—	—	3(a)	—	3
Included in other comprehensive income	—	—	(172)(b)	—	(172)
Included in payable for Zion Station decommissioning	—	(1)	—	—	(1)
Changes in collateral	—	—	8	—	8
Purchases, sales, issuances and settlements					—
Purchases	41	32	329(c)	17	419
Sales	—	(9)	—	—	(9)
Transfers into Level 3	—	—	(34)	—	(34)
Transfers out of Level 3	—	—	(39)	—	(39)
Balance as of June 30, 2012	$ 54	$ 59	$ 912	$ 17	$ 1,042
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the six months ended June 30, 2012	$ —	$ —	$ 78	$ —	$ 78

(a) Includes the reclassification of $56 million and $75 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and six months ended June 30, 2012, respectively.
(b) Includes $14 million of decreases in fair value and $121 million of increases in fair value and realized losses due to settlements of $161 million and $308 million associated with Generation's financial swap contract with ComEd for the three and six months ended June 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 six months ended June 30, 2013 and 2012:

	Operating Revenue	Purchased Power and Fuel	Other, net(a)
Total gains included in net income for the three months ended June 30, 2013	$ 148	$ 20	$ 1
Total gains (losses) included in net income for the six months ended June 30, 2013	$ (28)	$ 52	$ 2
Change in the unrealized gains relating to assets and liabilities held for the three months ended June 30, 2013	$ 153	$ 30	$ 1
Change in the unrealized gains relating to assets and liabilities held for the six months ended June 30, 2013	$ 29	$ 68	$ 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 June 30, 2012	$ (74)	$ 5	$ —
Total gains (losses) included in net income for the six months ended June 30, 2012	$ 7	$ (4)	$ —
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2012	$ (10)	$ (3)	$ —
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2012	$ 99	$ (21)	$ —

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

ComEd

The following tables present assets and liabilities measured and recorded at fair value on ComEd's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2013 and December 31, 2012:

As of June 30, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 70	$ —	$ —	$ 70
Rabbi trust investments				
Mutual funds(a)	6	—	—	6
Rabbi trust investments subtotal	6	—	—	6
Total assets	$ 76	$ —	$ —	$ 76
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark-to-market derivative liabilities(b)	—	—	(85)	(85)
Total liabilities	—	(8)	(85)	(93)
Total net assets (liabilities)	$ 76	$ (8)	$ (85)	$(17)

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 111	$ —	$ —	$ 111
Rabbi trust investments				
Mutual funds(a)	8	—	—	8
Rabbi trust investments subtotal	8	—	—	8
Total assets	$ 119	$ —	$ —	$ 119
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark-to-market derivative liabilities(b)(c)	—	—	(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 mutual funds held by the Rabbi trusts are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.
(b) The Level 3 balance includes the current and noncurrent liability of $16 million and $69 million at June 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.
(c) 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 six months ended June 30, 2013 and 2012:

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

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

(a) Includes $3 million of increases in fair value and $11 million of decreases in fair value and realized gains due to settlements of $82 million and $215 million associated with ComEd's financial swap contract with Generation for the three and six months ended June 30, 2013, respectively. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(b) Includes $9 million and $20 million of increases in the fair value and realized losses due to settlements of $1 million and $4 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three and six months ended June 30, 2013, respectively.

Three Months Ended June 30, 2012	Mark-to-Market Derivatives
Balance as of March 31, 2012	$ (823)
Total realized / unrealized gains included in regulatory assets(a)(b)	206
Balance as of June 30, 2012	$ (617)

Six Months Ended June 30, 2012	Mark-to-Market Derivatives
Balance as of December 31, 2011	$ (800)
Total realized / unrealized gains included in regulatory assets(a)(b)	183
Balance as of June 30, 2012	$ (617)

(a) Includes $14 million of increases in fair value and $121 million of decreases in fair value and realized gains due to settlements of $161 million and $308 million of associated with ComEd's financial swap contract with Generation for the three and six months ended June 30, 2012, respectively. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(b) Includes $30 million of decreases in fair value and $5 million of increases in fair value of floating-to-fixed energy swap contracts with unaffiliated suppliers for the three and six months ended June 30, 2012, respectively.

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

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PECO

The following tables present assets and liabilities measured and recorded at fair value on PECO's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2013 and December 31, 2012:

As of June 30, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 13	$ —	$ —	$ 13
Rabbi trust investments				
Mutual funds(a)(b)	9	—	—	9
Rabbi trust investments subtotal	9	—	—	9
Total assets	22	—	—	22
Liabilities				
Deferred compensation obligation	—	(16)	—	(16)
Total liabilities	—	(16)	—	(16)
Total net assets (liabilities)	$ 22	$ (16)	$ —	$ 6

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 346	$ —	$ —	$346
Rabbi trust investments				
Mutual funds(a)(b)	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) The mutual funds held by the Rabbi trusts are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.
(b) Excludes $14 million and $13 million of the cash surrender value of life insurance investments at June 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 six months ended June 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 June 30, 2013 and December 31, 2012:

As of June 30, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 365	$ —	$ —	$365
Rabbi trust investments				
Mutual funds(a)	5	—	—	5
Rabbi trust investments subtotal	5	—	—	5
Total assets	370	—	—	370
Liabilities				
Deferred compensation obligation	—	(5)	—	(5)
Total liabilities	—	(5)	—	(5)
Total net assets (liabilities)	$ 370	$ (5)	$ —	$365

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 33	$ —	$ —	$ 33
Rabbi trust investments				
Mutual funds(a)	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

(a) The mutual funds held by the Rabbi trusts are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.

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

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

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to 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, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

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

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. 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.

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

Rabbi Trust Investments (Exelon, Generation, ComEd, PECO and BGE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The investments in the Rabbi trusts are included in investments in the Registrants' Consolidated Balance Sheets. 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 non-exchange-based 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 non-exchange-based derivative contracts is 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 non-exchange-based 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' non-exchange-based derivatives are predominately at liquid trading points. For non-exchange-based derivatives that trade in less liquid markets with limited pricing information, such as the financial swap contract between Generation and ComEd, model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 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. 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 generally do not occur. 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.

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.

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

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 $2.10 and $0.14 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.

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 June 30, 2013(c)	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives — Economic Hedges (Generation)(a)	$ 485	Discounted Cash Flow	Forward power price	$15 - $87
			Forward gas price	$3.54 - $4.72
		Option Model	Volatility percentage	28% - 363%
Mark-to-market derivatives — Proprietary trading (Generation)(a)	$ 21	Discounted Cash Flow	Forward power price	$16 - $87
		Option Model	Volatility percentage	11% - 23%
Mark-to-market derivatives (ComEd)	$ (85)	Discounted Cash Flow	Forward heat rate(b)	8% - 9%
			Marketability reserve	3.5% - 8%
			Renewable factor	85% - 129%

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 $10 million as of June 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 June 30, 2013, Generation has outstanding commitments to invest in middle market lending of approximately $168 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 June 30, 2013, the percentage of expected generation hedged for the major reportable segments was 96%-99%, 78%-81%, and 41%-44% 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.

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

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. 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 2012 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 2012 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 30% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

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

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

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

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading activities, which included settled physical sales volumes of 1,995 GWhs and 3,567 GWhs for the three and six months ended June 30, 2013, respectively, and 4,248 GWhs and 6,077 GWhs for the three and six months ended June 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 June 30, 2013, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and $570 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 PECO Accounts Receivables Facility) and fixed-to-floating swaps would result in less than a $1 million decrease in Exelon Consolidated pre-tax income for the six months ended June 30, 2013. To manage foreign rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign rate derivatives, which are typically designated as economic hedges. Below is a summary of the interest rate and foreign currency hedges as of June 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)	$ —	$ 4	$ 18	$ (19)	$ 3	$ —	$ 3
Mark-to-market derivative assets (Noncurrent Assets)	31	6	19	(18)	38	32	70
Total mark-to-market derivative assets	$ 31	$ 10	$ 37	$ (37)	$ 41	$ 32	$ 73
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (2)	$ (18)	$ 18	$ (3)	$ —	$ (3)
Mark-to-market derivative liabilities (Noncurrent liabilities)	(15)	—	(18)	19	(14)	—	(14)
Total mark-to-market derivative liabilities	$ (16)	$ (2)	$ (36)	$ 37	$ (17)	$ —	$ (17)
Total mark-to-market derivative net assets (liabilities)	$ 15	$ 8	$ 1	$ —	$ 24	$ 32	$ 56

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	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:

	Gain (Loss) on Swaps Six Months Ended June 30,		Gain (Loss) on Borrowings Six Months Ended June 30,	
Income Statement Classification	2013	2012	2013	2012
Interest expense(a)	$ (9)	$ (2)	$ 1	$ (3)

(a) For the six months ended June 30, 2013, the loss on the swaps in the table above includes $8 million reclassified to earnings, with an immaterial amount excluded from hedge effectiveness testing.

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

At June 30, 2013 and December 31, 2012, Exelon and Generation had $650 million of notional amounts of fixed-to-floating fair value hedges outstanding related to interest rate swaps, with unrealized gain of $38 million and $49 million, respectively, which expire in 2015. Upon merger closing, $550 million of fixed-to-floating interest rate swaps previously at Constellation with a fair value of $44 million, as of March 12, 2012, were re-designated as fair value hedges. During the six months ended June 30, 2013 and June 30, 2012, the impact of loss on the results of operations as a result of ineffectiveness from fair value hedges was immaterial.

Cash Flow Hedges. In connection with the DOE guaranteed loan for the Antelope Valley 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, by which date Generation anticipates the DOE loan to be fully drawn. 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 several additional advances subsequently. Generation has entered into a series of fixed-to-floating interest rate swaps with an aggregated notional amount of $321 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 $164 million. At June 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 $14 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 June 30, 2013 and expire in 2027. After the closing of the merger with Constellation, the swaps were re-designated as cash flow hedges. At June 30, 2013, the subsidiary had an immaterial current and 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 June 30, 2013 and expires in 2030. This swap is designated as a cash flow hedge. At June 30, 2013, the subsidiary had an immaterial current derivative liability and an immaterial current derivative asset related to the swap.

Since the third quarter of 2012, Exelon has entered into $350 million floating-to-fixed interest rate hedges to manage interest rate risks associated with anticipated future debt issuance. These swaps are designated as cash flow hedges. At June 30, 2013, Exelon had a $23 million current derivative asset related to these swaps.

During the six months ended June 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 June 30, 2013, Generation had $336 million in notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $31 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 June 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 six months ended June 30, 2013 and the period from March 12 to June 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 June 30, 2013 and December 31, 2012, $3 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 June 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)	$ 2,585	$ 1,924	$ (3,667)	$ 842	$ —	$ 842
Mark-to-market derivative assets (noncurrent assets)	1,471	522	(1,291)	702	—	702
Total mark-to-market derivative assets	$ 4,056	$ 2,446	$ (4,958)	$1,544	$ —	$ 1,544
Mark-to-market derivative liabilities (current liabilities)	$ (2,201)	$ (1,865)	$ 3,938	$ (128)	$ (16)	$ (144)
Mark-to-market derivative liabilities (noncurrent liabilities)	(941)	(502)	1,348	(95)	(69)	(164)
Total mark-to-market derivative liabilities	$ (3,142)	$ (2,367)	$ 5,286	$ (223)	$ (85)	$ (308)
Total mark-to-market derivative net assets (liabilities)	$ 914	$ 79	$ 328	$1,321	$ (85)	$ 1,236

(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 $17 million and $49 million, respectively, and current and noncurrent liabilities are shown net of collateral of $254 million and $106 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $328 million at June 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 from the date of de-designation. The net unrealized gains associated with the de-designated cash flow hedges prior to the merger was $1,928 million including $693 million related to the intercompany swap with ComEd. Approximately $326 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.

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

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 June 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 six months ended June 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	
Three Months Ended June 30, 2013	Income Statement Location	Generation Energy-Related Hedges	Exelon Total Cash Flow Hedges
Accumulated OCI derivative gain at March 31, 2013		$ 397(a)(c)	$ 310
Effective portion of changes in fair value		—	21(d)
Reclassifications from accumulated OCI to net income	Operating Revenues	(142)(b)	(86)
Accumulated OCI derivative gain at June 30, 2013		$ 255(c)	$ 245

(a) Includes $58 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, as of March 31, 2013.
(b) Includes $58 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c) Excludes $11 million of losses and $16 million of losses net of taxes, related to interest rate swaps and treasury rate locks as of June 30, 2013 and March 31, 2013, respectively.
(d) Includes $18 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	
Six Months Ended June 30, 2013	Income Statement Location	Generation Energy-Related Hedges	Exelon Total Cash Flow Hedges
Accumulated OCI derivative gain at December 31, 2012		$ 532(a)(c)	$ 368
Effective portion of changes in fair value		—	21(d)
Reclassifications from accumulated OCI to net income	Operating Revenues	(277)(b)	(144)
Accumulated OCI derivative gain at June 30, 2013		$ 255(c)	$ 245

(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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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(b) Includes $133 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c) Excludes $11 million of losses and $20 million of losses, net of taxes, related to interest rate swaps and treasury locks as of June 30, 2013 and December 31, 2012, respectively.
(d) Includes $22 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.

Three Months Ended June 30, 2012	Income Statement Location	Generation Energy-Related Hedges	Exelon Total Cash Flow Hedges
Accumulated OCI derivative gain at March 31, 2012		$ 1,166(a)(c)	$ 703
Effective portion of changes in fair value		—(e)	(17)(d)
Reclassifications from accumulated OCI to net income	Operating Revenues	(243)(b)	(139)
Accumulated OCI derivative gain at June 30, 2012		$ 923(a)(c)	$ 547

(a) Includes $315 million and $419 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd as of June 30, 2012 and March 31, 2012, respectively.
(b) Includes a $104 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 $23 million of losses and $12 million of gains, net of taxes, related to interest rate swaps and treasury rate locks for the three months ended June 30, 2012 and month ended March 31, 2012, respectively.
(d) Includes $12 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	
Six Months Ended June 30, 2012	Income Statement Location	Generation Energy-Related Hedges	Exelon 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)	300(d)
Reclassifications from accumulated OCI to net income	Operating Revenues	(437)(b)	(244)
Ineffective portion recognized in income	Operating Revenues	3	3
Accumulated OCI derivative gain at June 30, 2012		$ 923(a)(c)	$ 547

(a) Includes $315 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 June 30, 2012 and December 31, 2011.
(b) Includes $193 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 $23 million of losses and $10 million of losses, net of taxes, related to interest rate swaps and treasury rate locks for the six months ended June 30, 2012 and year ended December 31, 2011, respectively.
(d) Includes $23 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.

During the three and six months ended June 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 $236 million and a $459 million pre-tax gain and $402 million and $722 million pre-tax gain,

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

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. This price difference was actively managed through other instruments, which include financial transmission rights, whose changes in fair value are recognized in earnings each period, and auction revenue rights. Changes in cash flow hedge ineffectiveness, were losses of $5 million for the six months ended June 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 $141 million and $240 million pre-tax gain for the three and six months ended June 30, 2013, respectively, and a $230 million and $403 million pre-tax gain for the three and six months ended June 30, 2012,respectively. Changes in cash flow hedge ineffectiveness was losses of $5 million for the six months ended June 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 six months ended June 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.

	Generation			Intercompany Eliminations	Exelon
Three Months Ended June 30, 2013	Operating Revenues	Purchased Power and Fuel	Total	Operating Revenues(a)	Total
Change in fair value	$ 460	$ (77)	$383	$ (13)	$ 370
Reclassification to realized at settlement	44	1	45	3	48
Net mark-to-market gains (losses)	$ 504	$ (76)	$428	$ (10)	$ 418

	Generation			Intercompany Eliminations	Exelon
Six Months Ended June 30, 2013	Operating Revenues	Purchased Power and Fuel	Total	Operating Revenues(a)	Total
Change in fair value	$ (26)	$ 69	$ 43	$ (6)	$ 37
Reclassification to realized at settlement	(56)	38	(18)	13	(5)
Net mark-to-market gains (losses)	$ (82)	$ 107	$ 25	$ 7	$ 32

	Generation			Intercompany Eliminations	Exelon
Three Months Ended June 30, 2012	Operating Revenues	Purchased Power and Fuel	Total	Operating Revenues(a)	Total
Change in fair value	$ 44	$ 12	$ 56	$ 16	$ 72
Reclassification to realized at settlement	(54)	198	144	(10)	134
Net mark-to-market (losses)	$ (10)	$ 210	$200	$ 6	$ 206

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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	Generation			Intercompany Eliminations	Exelon
Six Months Ended June 30, 2012	Operating Revenues	Purchased Power and Fuel	Total	Operating Revenues(a)	Total
Change in fair value	$ 177	$ (28)	$149	$ 27	$ 176
Reclassification to realized at settlement	(109)	225	116	(10)	106
Net mark-to-market (losses)	$ 68	$ 197	$265	$ 17	$ 282

(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 six months ended June 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 June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Change in fair value	Operating Revenue	$ 5	$ 12	$ 1	$ 14
Reclassification to realized at settlement	Operating Revenue	(2)	31	4	32
Net mark-to-market gains	Operating Revenue	$ 3	$ 43	$ 5	$ 46

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

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

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

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of June 30, 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 $41 million, $44 million and $33 million, respectively.

Rating as of June 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	$ 1,744	$ 139	$ 1,605	1	$ 462
Non-investment grade	40	31	9	—	—
No external ratings					
Internally rated — investment grade	456	5	451	1	247
Internally rated — non-investment grade	62	1	61	—	—
Total	$ 2,302	$ 176	$ 2,126	2	$ 709

Net Credit Exposure by Type of Counterparty	As of June 30, 2013
Investor-owned utilities, marketers and power producers	$ 761
Energy cooperatives and municipalities	926
Financial institutions	386
Other	53
Total	$ 2,126

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of June 30, 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 3 — Regulatory Matters of the Exelon 2012 Form 10-K for further 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 June 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 June 30, 2013, PECO had immaterial credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 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 June 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 June 30, 2013, BGE had credit exposure of $2 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		June 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)
$ (1,222)	$1,046	$ (176)

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 $546 million and letters of credit posted of $356 million and cash collateral held of $215 million and letters of credit held of $30 million as of June 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 $1,878 million as of June 30, 2013 and $2,007 million 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 June 30, 2013, Generation's and Exelon's swaps were in an asset position, with a fair value of $24 million and $56 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 June 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 June 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 June 30, 2013, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of June 30, 2013, PECO could have been required to post approximately $31 million of collateral to its counterparties.

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

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

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of June 30, 2013, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of June 30, 2013, BGE could have been required to post approximately $86 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 June 30, 2013 and December 31, 2012:

Commercial Paper Borrowings	June 30, 2013	December 31, 2012
Exelon Corporate	$ —	$ —
Generation	276	—
ComEd	374	—
PECO	—	—
BGE	—	—

Credit Facilities

Exelon had bank lines of credit under committed credit facilities at June 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 2017	Letters of credit and cash
Generation			
Syndicated Revolver	5.3	August 2017	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 2017	Letters of credit and cash
BGE			
Syndicated Revolver	0.6	August 2017	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, 2013 and are solely utilized to issue letters of credit. As of June 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 June 30, 2013, there were no borrowings under the Registrants' credit facilities.

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.

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 agreement also requires each entity to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of each entity.

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

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 June 10, 2013, Exelon Corporate, Generation, PECO and BGE began the process of extending their respective unsecured syndicated revolving credit facilities, with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively. The transactions are expected to close and become effective in August 2013, with maturities of five years from the close of the transactions. The new covenants are expected to be substantially consistent with existing covenants. Generally, it is expected that costs incurred to amend and extend the facilities will be amortized over the newly extended lives of the facilities.

Long-Term Debt

Issuance of Long-Term Debt

During the six months ended June 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%	July 22, 2016	$ 3	Used to fund Upstream gas activities
Generation	DOE Project Financing	2.535 - 2.922%	January 5, 2037	$ 197	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
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 six months ended June 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	$ 787	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	DOE Project Financing	3.092%	January 5, 2037	$ 69	Funding for Antelope Valley Solar Development

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 six months ended June 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	$ 1
Generation	Solar Revolver	1.950%	July 7, 2014	$ 6
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
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 July 1, 2013, ComEd retired $127 million aggregate principal of its 7.500% Series 94 First Mortgage Bonds due July 1, 2013.

On July 1, 2013, BGE retired $400 million aggregate principal of its 6.125% Senior Notes due July 1, 2013

During the six months ended June 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	$ 1
Generation	Armstrong Co. tax-exempt	5.00%	December 1, 2042	$ 46
Generation	Solar Revolver	2.49%	July 7, 2014	$ 6
Generation	Upstream Gas Lending Agreement	2.27%	July 16, 2016	$ 3
Exelon	Senior Notes	7.60%	April 1, 2032	$ 441
Exelon	Medium Term Notes	7.30%	June 1, 2012	$ 2

Accounts Receivable Agreement

PECO is 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 is classified as a short-term note payable on Exelon's and PECO's Consolidated Balance Sheets. As of June 30, 2013 and December 31, 2012, the financial institution's undivided interest in Exelon's and PECO's gross accounts receivable was equivalent to $286 million and $289 million, respectively, which represents the financial institution's interest in PECO's eligible receivables as calculated under the terms of the agreement. The agreement requires PECO to maintain eligible receivables at least equivalent to the financial

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

institution's undivided interest. Upon termination or liquidation of this agreement, the financial institution is entitled to recover up to $210 million plus the accrued yield payable from its undivided interest in PECO's receivables. The amended agreement terminates on August 30, 2013 unless extended in accordance with its terms. As of June 30, 2013, PECO was in compliance with the requirements of the agreement. In the event the agreement is not extended, PECO has sufficient short-term liquidity and may seek alternate financing.

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 June 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	4.1	3.5	5.6	2.9	5.6
Qualified nuclear decommissioning trust fund income	(1.8)	(2.7)	—	—	—
Domestic production activities deduction	0.1	0.2	—	—	—
Tax exempt income	(0.1)	(0.2)	—	—	—
Health care reform legislation	0.1	—	0.4	—	(0.3)
Amortization of investment tax credit, net deferred taxes	(1.8)	(2.5)	(0.3)	(0.1)	(0.6)
Plant basis differences	(1.4)	—	(0.4)	(8.6)	(0.7)
Production tax credits and other credits	(1.4)	(2.2)	—	—	—
Other	(0.3)	0.1	0.4	(0.1)	—
Effective income tax rate	32.5 %	31.2 %	40.7 %	29.1 %	39.0 %

For the Six Months Ended June 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	8.6	0.4	4.1	2.9	5.7
Qualified nuclear decommissioning trust fund income	2.8	4.8	—	—	—
Domestic production activities deduction	—	(0.1)	—	—	—
Tax exempt income	(0.2)	(0.4)	—	—	—
Health care reform legislation	0.2	—	5.7	—	0.2
Amortization of investment tax credit, net deferred taxes	(3.5)	(5.6)	(4.9)	(0.1)	(0.3)
Plant basis differences	(3.1)	—	(8.7)	(7.5)	(0.6)
Production tax credits and other credits	(2.8)	(4.9)	(0.3)	—	—
Other	0.1	3.1	5.5	—	(0.2)
Effective income tax rate	37.1 %	32.3 %	36.4 %	30.3 %	39.8 %

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

For the Three Months Ended June 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	3.5	2.3	5.2	3.1	6.2
Qualified nuclear decommissioning trust fund income	(2.0)	(3.8)	—	—	—
Domestic production activities deduction	0.7	1.6	—	—	—
Tax exempt income	(0.4)	(0.8)	—	—	—
Health care reform legislation	0.3	—	1.0	—	2.7
Amortization of investment tax credit, net deferred taxes	(0.7)	(0.7)	(0.8)	(0.3)	(1.7)
Plant basis differences	(0.7)	—	0.1	(3.6)	(4.7)
Production tax credits and other credits	(2.2)	(4.0)	—	—	—
Merger expenses(c)	(0.8)	—	—	—	—
Other	(2.3)	(3.6)	0.3	0.2	(1.5)
Effective income tax rate	30.4 %	26.0 %	40.8 %	34.4 %	36.0 %

For the Six Months Ended June 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	(10.7)	1.6	5.7	3.3	2.3
Qualified nuclear decommissioning trust fund income	6.3	8.0	—	—	—
Domestic production activities deduction	(0.2)	(0.2)	—	—	—
Tax exempt income	(0.4)	(0.5)	—	—	—
Health care reform legislation	0.2	—	0.6	—	(3.1)
Amortization of investment tax credit, net deferred taxes	(0.7)	(0.6)	(0.5)	(0.3)	3.8
Plant basis differences	(0.6)	—	—	(3.6)	10.6
Production tax credits and other credits	(2.6)	(3.4)	—	—	—
Fines and Penalties	6.1	7.6	—	—	—
Merger expenses(c)	5.6	—	—	—	(18.3)
Other	(1.3)	(1.0)	0.3	—	3.0
Effective income tax rate	36.7 %	46.5 %	41.1 %	34.4 %	33.3 %

(a) Exelon activity for the three and six months ended June 30, 2012 includes the results of Constellation and BGE for March 12, 2012 — June 30, 2012. Generation activity for the three and six months ended June 30, 2012 includes the results of Constellation for March 12, 2012 — June 30, 2012.
(b) BGE activity represents the activity for the three and six months ended June 30, 2012. BGE recognized a loss before income taxes for the six months ended June 30, 2012. As a result, positive percentages represent an income tax benefit for BGE for the six months ended June 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.

Accounting for Uncertainty in Income Taxes

Exelon, Generation, ComEd, PECO, and BGE have $2,220 million, $1,363 million, $331 million, $44 million, and $0 million, of unrecognized tax benefits as of June 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 June 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 and $446 million, respectively, 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

In 2013, as a result of the anticipated completion of federal income tax audits for legacy Constellation, it is reasonably possible Exelon and Generation may reduce their unrecognized tax benefits by approximately $35 million and $35 million, respectively.

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 $86 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. Exelon expects to initiate litigation in 2013 to contest the IRS's disallowance of the like-kind exchange position. 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. The IRS also continues to assert an $86 million penalty for a substantial understatement of tax with respect to the like-kind exchange position. Exelon continues to believe that it is unlikely that the penalty assertion will ultimately be sustained and therefore no liability for the penalty has been recorded.

This determination for accounting purposes does not alter Exelon's intent to aggressively litigate the issue through appeals, if necessary, which could take three to five years. Exelon currently expects to initiate the litigation in the United States Tax Court, whose decisions are not controlled by the Federal Circuit's decision in Consolidated Edison.

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

As of June 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 $306 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 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 will assess 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, 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 June 30, 2013:

Nuclear decommissioning ARO at December 31, 2012(a)	$4,741
Accretion expense	129
Costs incurred to decommission retired plants	(2)
Nuclear decommissioning ARO at June 30, 2013(a)	$4,868

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

Nuclear Decommissioning Trust Fund Investments

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

The NDT funds associated with the former ComEd, former PECO 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 currently collects funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are expected to continue through the operating lives of the plants. The amounts collected from PECO customers are remitted to Generation and

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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deposited into the NDT funds. 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 $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. 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 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.

At June 30, 2013 and December 31, 2012, Exelon and Generation had NDT fund investments totaling $7,463 million and $7,248 million, respectively. The following table provides unrealized gains (losses) on NDT funds for the three and six months ended June 30, 2013 and 2012:

	Exelon and Generation			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net unrealized gains (losses) on decommissioning trust funds — Regulatory Agreement Units(a)	$ (102)	$ (96)	$ 92	$ 150
Net unrealized gains (losses) on decommissioning trust funds — Non-Regulatory Agreement Units(b)(c)	(40)	(35)	24	30

(a) Net unrealized gains (losses) related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets and noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.

(b) Excludes $2 million and $ 4 million of net unrealized gains related to the Zion Station pledged assets for the three months ended June 30, 2013 and 2012, respectively, and $3 million and $38 million of net unrealized gains related to the Zion Station pledged assets for the six months ended June 30, 2013 and 2012, respectively. Net unrealized gains related to Zion Station pledged assets are included in the Payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets.

(c) Net unrealized gains (losses) 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.

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.

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. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers. Generation has retained its obligation to transfer the SNF at Zion Station to the DOE for ultimate disposal and has a liability of approximately $81 million, which is included within the nuclear decommissioning ARO at June 30, 2013. Generation also has retained NDT assets to fund its obligation to maintain and transfer the SNF at Zion Station.

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

The following table provides the pledged assets and payable to ZionSolutions, and withdrawals by ZionSolutions at June 30, 2013 and December 31, 2012:

	Exelon and Generation	
	June 30, 2013	December 31, 2012
Carrying value of Zion Station pledged assets	$538	$ 614
Payable to Zion Solutions(a)	491	564
Current portion of payable to Zion Solutions(b)	118	132
Withdrawals by Zion Solutions to pay decommissioning costs(c)	414	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.

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 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. Generation anticipates that the NRC will issue its findings sometime this year. 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 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.

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

Defined Benefit Pension and Other Postretirement Benefits

During the first quarter of 2013, Exelon received an updated valuation of its legacy Exelon 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 approximately by $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 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 six months ended June 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. Legacy Constellation 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 June 30,		Other Postretirement Benefits Three Months Ended June 30,	
	2013	2012	2013	2012
Service cost	$ 79	$ 74	$ 40	$ 39
Interest cost	163	179	49	54
Expected return on assets	(254)	(253)	(33)	(29)
Amortization of:				
Transition obligation	—	—	—	2
Prior service cost (benefit)	4	3	(6)	(3)
Actuarial loss	141	115	21	19
Contractual termination benefit cost(a)	—	14	—	6
Curtailment gain	—	—	—	(2)
Net periodic benefit cost	$ 133	$ 132	$ 71	$ 86

	Pension Benefits Six Months Ended June 30,		Other Postretirement Benefits Six Months Ended June 30,	
	2013	2012	2013	2012
Service cost	$ 159	$ 135	$ 81	$ 76
Interest cost	326	343	97	104
Expected return on assets	(508)	(484)	(66)	(58)
Amortization of:				
Transition obligation	—	—	—	6
Prior service cost (benefit)	7	7	(10)	(6)
Actuarial loss	281	221	42	38
Contractual termination benefit cost(a)	—	14	—	6
Curtailment gain	—	—	—	(2)
Net periodic benefit cost	$ 265	$ 236	$ 144	$ 164

(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.

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

The amounts below were included in capital additions and operating and maintenance expense during the three and six months ended June 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.

Pension and Other Postretirement Benefit Costs	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Generation	$ 87	$ 94	$ 173	$ 175
ComEd	77	68	154	137
PECO	10	13	21	26
BGE(a)(b)	14	18	27	32
BSC(c)	16	25	34	42

(a) BGE's pension and postretirement benefit costs for the six months ended June 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 six months ended June 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 six months ended June 30, 2012 includes a $3 million contractual termination benefit charge, which was recorded as a regulatory asset as of June 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 June 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 expects to contribute $255 million to its qualified pension plans in 2013, of which Generation, ComEd, PECO and BGE will contribute $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 $81 million in 2013, of which Generation, ComEd, PECO, and BGE will make payments of $7 million, $1 million, $1 million, and $2 million, respectively.

Unlike qualified pension plans, other postretirement plans are not subject to regulatory 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.

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

Exelon has developed and implemented an 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.

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 six months ended June 30, 2013 and 2012:

	Three Months Ended June 30,		Six Months Ended June 30,	
Savings Plan Matching Contributions	2013	2012	2013	2012
Exelon	$ 21	$ 19	$ 43	$ 35
Generation	10	8	21	16
ComEd	5	5	10	9
PECO	2	2	4	4
BGE(a)	2	1	4	3
BSC(b)	2	3	4	4

(a) BGE's matching contributions for the six months ended June 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 six months ended June 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 June 30, 2013, there were approximately 16 million shares authorized for issuance under the LTIP. For the three and six months ended June 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.

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(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 six months ended June 30, 2013 and 2012:

Components of Stock-Based Compensation Expense	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Performance share awards	$ 13	$ 10	$ 29	$ 26
Stock options	1	4	2	11
Restricted stock units	16	11	36	30
Other stock-based awards	2	1	3	2
Total stock-based compensation expense included in operating and maintenance expense	32	26	70	69
Income tax benefit	(12)	(10)	(27)	(26)
Total after-tax stock-based compensation expense	$ 20	$ 16	$ 43	$ 43

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

Subsidiaries	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Generation	$ 13	$ 9	$ 28	$ 24
ComEd	2	2	4	7
PECO	1	1	3	3
BGE(a)	2	1	4	3
BSC(b)	14	13	31	32
Total(c)	$ 32	$ 26	$ 70	$ 69

(a) BGE's stock-based compensation expense (pre-tax) for the six months ended June 30, 2012 includes $2 million of cost incurred 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 six months ended June 30, 2012 shown in the table titled Components of Stock-Based Compensation Expense 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 six months ended June 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 consider 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 six months ended June 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 June 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 2.0 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 June 30, 2013 and December 31, 2012, Exelon had obligations related to outstanding restricted stock units not yet settled of $60 million and $58 million, respectively, which are included in common stock in Exelon’s Consolidated Balance Sheets. As of June 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 June 30, 2013 and 2012, Exelon settled restricted stock units with a fair value totaling $1 million and $2 million, respectively. During the six months ended June 30, 2013 and 2012, Exelon settled restricted stock units with a fair value totaling $23 million and $21 million, respectively. At June 30, 2013, $81 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.4 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 June 30, 2013 and December 31, 2012, Exelon had obligations related to outstanding performance shares not yet settled of $54 million and $53 million, respectively. During the three months ended June 30, 2013 and 2012, Exelon settled performance shares with a fair value totaling $1 million and $19 million, respectively, of which $1 million and $3 million was paid in cash, respectively. During the six months ended June 30, 2013 and 2012, Exelon settled performance shares with a fair value totaling $23 million and $19 million, respectively, of which $10 million and $3 million was paid in cash, respectively. As of June 30, 2013, $39 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 2.5 years. In addition, as of June 30, 2013, $25 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 1.6 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 six months ended June 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	24	(1)	87	(6)	31	135
Amounts reclassified from AOCI(b)	(147)	—	101	—	5	(41)
Net current-period OCI	(123)	(1)	188	(6)	36	94
Ending balance	$ 245	$ (1)	$ (2,949)	$ (6)	$ 38	$(2,673)
Generation(a)						
Beginning balance	$ 512	$ —	$ —	$ —	$ 1	$ 513
OCI before reclassifications	12	(1)	—	(6)	31	36
Amounts reclassified from AOCI(b)	(279)	—	—	—	5	(274)
Net current-period OCI	(267)	(1)	—	(6)	36	(238)
Ending balance	$ 245	$ (1)	$ —	$ (6)	$ 37	$ 275
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)

The following table presents amounts reclassified out of AOCI to Net Income during the three and six months ended June 30, 2013:

Three Months Ended June 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	ComEd	PECO	BGE	
Gains and (losses) on cash flow hedges						
Energy related hedges	$ 141	$ 236	$ —	$ —	$ —	Operating revenues
Other cash flow hedges	—	1	—	—	—	Interest expense
	141	237	—	—	—	Total before tax
	(52)	(93)	—	—	—	Tax (expense)
	$ 89	$ 144	$ —	$ —	$ —	Net of tax
Amortization of pension and other postretirement benefit plan items						
Prior service costs	$ (1)	$ —	$ —	$ —	$ —	(b)
Actuarial gains/ (losses)	(82)	—	—	—	—	(b)
	(83)	—	—	—	—	Total before tax
	32	—	—	—	—	Tax benefit
	$ (51)	$ —	$ —	$ —	$ —	Net of tax
Equity investments						
Capital activity	$ (5)	$ (5)	$ —	$ —	$ —	Equity in losses of unconsolidated affiliates
	(5)	(5)	—	—	—	Total before tax
	2	2	—	—	—	Tax benefit
	$ (3)	$ (3)	$ —	$ —	$ —	Net of tax
Total Reclassifications for the period	$ 35	$ 141	$ —	$ —	$ —	Net of Tax

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

Six Months Ended June 30, 2013

Details about AOCI components	Items reclassified out of AOCI (a) Exelon	Generation	ComEd	PECO	BGE	Affected line item in the statement where Net Income is presented
Gains and (losses) on cash flow hedges						
Energy related hedges	$ 240	$ 459	$ —	$ —	$—	Operating revenues
Other cash flow hedges	(1)	1	—	—	—	Interest expense
	239	460	—	—	—	Total before tax
	(92)	(181)	—	—	—	Tax (expense)
	$ 147	$ 279	$ —	$ —	$—	Net of tax
Amortization of pension and other postretirement benefit plan items						
Prior service costs	$ (1)	$ —	$ —	$ —	$—	(b)
Actuarial gains/ (losses)	(165)	—	—	—	—	(b)
	(166)	—	—	—	—	Total before tax
	65	—	—	—	—	Tax benefit
	$(101)	$ —	$ —	$ —	$—	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	$ 41	$ 274	$ —	$ —	$—	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).

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 June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Net income attributable to common shareholders	$ 490	$ 286	$ 486	$ 486
Average common shares outstanding — basic	856	853	856	779
Assumed exercise of stock options, performance share awards and restricted stock	4	3	3	2
Average common shares outstanding — diluted	860	856	859	781

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

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 17 million and 18 million for the three and six months ended June 30, 2013, respectively, and 17 million and 13 million for the three and six months ended June 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 June 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.

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 June 30, 2013, Generation's short-and long-term 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)	Power-Related Purchases(b)	Transmission Rights Purchases(c)	Purchased Energy from CENG	Total
2013	$ 192	$ 30	$ 14	$ 406	$ 642
2014	372	98	26	668	1,164
2015	367	65	13	—	445
2016	283	39	2	—	324
2017	222	10	2	—	234
Thereafter	528	4	34	—	566
Total	$ 1,964	$ 246	$ 91	$ 1,074	$3,375

(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 June 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.

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

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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.

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

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
ComEd							
Electric supply procurement(a)	$1,053	$317	$323	$136	$137	$140	$ —
Renewable energy and RECs(b)	1,615	31	67	74	76	77	1,290
PECO							
Electric supply procurement(c)	886	516	308	62	—	—	—
AECs	22	5	5	2	2	2	6
BGE							
Electric supply procurement(d)	1,480	557	689	234	—	—	—
Curtailment services(e)	160	26	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 associate 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 entered into various contracts with curtailment services providers related to transactions in PJM's capacity market. See Note 5 — Regulatory Matters for additional information.

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

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 June 30, 2013, these net commitments were as follows:

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
Generation	$8,485	$820	$1,207	$1,244	$1,027	$1,078	$ 3,109
PECO	492	91	117	95	72	36	81
BGE	593	71	84	52	51	51	284

Other Purchase Obligations

The Registrants' other purchase obligations as of June 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	$719	$184	$205	$130	$42	$39	$ 119
Generation	616	142	156	127	41	38	112
ComEd	16	2	14	—	—	—	—
PECO	48	19	19	1	1	1	7
BGE	2	1	1	—	—	—	—

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 additional phases to come online and an expectation of full commercial operation in December 2013. Exelon has been informed by First Solar of issues relating to potential delays in the certification of certain components relating to the final two blocks of the project which could delay commercial operation of these two blocks until the first quarter of 2014. Generation's estimated remaining commitment for the project is $239 million.

On July 3, 2013, Generation executed a Turbine Supply Agreement to expand its Beebe project in Michigan, the total commitment under the contract is $58 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 site with 120MW of new natural gas-fired generation to satisfy certain merger commitments, the total commitment under the contract is $89 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.

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

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.

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 June 30, 2013, representing commitments potentially triggered by future events were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Letters of credit (non-debt)(a)	$1,405	$ 1,354	$ 26	$ 22	$ 1
Guarantees	5,506(b)	1,214(c)	209(d)	181(e)	252(f)
Nuclear insurance premiums(g)	2,585	2,585	—	—	—
Total commercial commitments	$9,496	$ 5,153	$ 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 $0.8 billion at June 30, 2013, which represents the total amount Exelon could be required to fund based on June 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 June 30, 2013, which represents the total amount Generation could be required to fund based on June 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 requires mandatory participation in a retrospective rating plan for power reactors (currently 104 reactors) resulting in $12.2 billion in funds available for public liability claims for any single incident at any power reactor site that exceeds the primary level of financial protection currently required ($375 million). 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 $2.6 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.

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 June 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 guarantees 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 would be required to perform in the event that TII does not pay any obligation covered by the guarantee that is not otherwise subject to a dispute resolution process. Generation's maximum obligation under the guarantee is $95 million as of June 30, 2013. Generation believes that it is remote that it will be required to make payments under the guarantee and has not recorded a liability associated with this guarantee. The exposures covered by this guarantee expired in part during 2008. Generation expects that the remaining exposure will expire in the third quarter of 2013. The guarantee of $95 million is included above in the Commercial Commitments table under guarantees.

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 2019.
- BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor's acquisition. Two gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. One gas purification site is in the initial stages of investigation at the direction of the MDE.

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. See Note 5 — Regulatory Matters for additional information regarding the associated regulatory assets.

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

As of June 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:

June 30, 2013	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 334	$ 283
Generation	42	—
ComEd	245	240
PECO	46	43
BGE	1	—

December 31, 2012	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 338	$ 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. 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 a liability in its Consolidated Balance Sheets of approximately $23 million to comply with the consent decree. The remaining liability as of June 30, 2013, is approximately $3 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 June 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.

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 June 30, 2013, Generation had $57 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 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 may 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 June 30, 2013, Exelon had a $683 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.

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. 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 June 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 June 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.

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 2012 Form 10-K that (i) it has accrued a probable amount of approximately $9 million for estimated environmental investigation and remediation costs under CERCLA, or similar laws, for the investigation and remediation of contaminated property at 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 reorganization process will likely extend beyond one year and 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 June 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 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. 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. At this stage of the litigation, Exelon cannot estimate a range of loss, if any.

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. 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.

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 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 cunum* decision, dismissed industry and state petitions challenging the U.S. EPA's Tailoring Rule based on petitioners' lack of standing. Further, in the same decision, the court denied all challenges to U.S. EPA's endangerment finding, and the Agency's "Tailpipe Rule" for cars and light trucks. In August 2012, several industry parties filed petitions for an *en banc* rehearing of the Agency's GHG regulations with the D.C. Circuit court. On September 6, 2012 the Circuit Court ordered the U.S. EPA, intervening groups, and some states to reply to the industry petitions. 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(a) of the Clean Air Act is to focus on establishing carbon regulations for new fossil-fuel power plants. This rulemaking is to be proposed no later than September 20, 2013 and is to be finalized "in a timely fashion." This rulemaking will replace, in an as yet unknown manner, the April 13, 2012 proposed rulemaking for new fossil-fired power plants that EPA had previously published in the Federal Register.

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.

Given the low carbon nature of Generation's fleet and the absence of actual proposed rulemaking language, Generation is unable to estimate the potential impacts of Section 111(a) and Section 111(d).

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.

At June 30, 2013 and December 31, 2012, Generation had reserved approximately $66 million and $63 million, respectively, in total for asbestos-related bodily injury claims. As of June 30, 2013, approximately $18 million of this amount related to 198 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).

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 as of June 30, 2013, 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 June 30, 2013, 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 opt-outs and objections are due by August 19, 2013 with a final settlement hearing scheduled for November 1, 2013. This settlement will resolve all of Constellation's litigation arising from the 2008 Securities Class Action lawsuit.

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.

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

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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 six months ended June 30, 2013 and 2012:

Three Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory Agreement Units	$ 47	$ 47	$ —	$ —	$ —
Non-Regulatory Agreement Units	16	16	—	—	—
Net unrealized losses on decommissioning trust funds					
Regulatory Agreement Units	(102)	(102)	—	—	—
Non-Regulatory Agreement Units	(40)	(40)	—	—	—
Net unrealized gains on pledged assets					
Zion Station decommissioning	2	2	—	—	—
Regulatory offset to decommissioning trust fund-related activities(b)	40	40	—	—	—
Total decommissioning-related activities	(37)	(37)	—	—	—
Investment income	2	—	—	(1)	2(c)
Long-term lease income	5	—	—	—	—
Interest income (expense) related to uncertain income tax positions	(1)	(2)	—	—	—
AFUDC — Equity	5	—	3	1	2
Other	9	6	3	—	—
Other, net	$ (17)	$ (33)	$ 6	$ —	$ 4

Six Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory Agreement Units	$ 84	$ 84	$ —	$ —	$ —
Non-Regulatory Agreement Units	30	30	—	—	—
Net unrealized gains on decommissioning trust funds					
Regulatory Agreement Units	92	92	—	—	—
Non-Regulatory Agreement Units	24	24	—	—	—
Net unrealized gains on pledged assets					
Zion Station decommissioning	3	3	—	—	—
Regulatory offset to decommissioning trust fund-related activities(b)	(148)	(148)	—	—	—
Total decommissioning-related activities	85	85	—	—	—
Investment income (expense)	5	(1)	—	(1)	5(c)
Long-term lease income	13	—	—	—	—
Interest income related to uncertain income tax positions	24	3	—	—	—
AFUDC — Equity	12	—	6	2	4
Other	16	8	5	2	—
Other, net	$ 155	$ 95	$ 11	$ 3	$ 9

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

Three Months Ended June 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory Agreement Units	$ 50	$ 50	$ —	$ —	$—
Non-Regulatory Agreement Units	19	19	—	—	—
Net unrealized losses on decommissioning trust funds					
Regulatory Agreement Units	(97)	(97)	—	—	—
Non-Regulatory Agreement Units	(35)	(35)	—	—	—
Net unrealized losses on pledged assets					
Zion Station decommissioning	4	4	—	—	—
Regulatory offset to decommissioning trust fund-related activities(b)	31	31	—	—	—
Total decommissioning-related activities	(28)	(28)	—	—	—
Investment income	6	1	—	1	3
Long-term lease income	7	—	—	—	—
Interest income related to uncertain income tax positions	14	—	1	—	—
Credit facility termination fees	(42)	(42)	—	—	—
AFUDC — Equity	3	—	—	1	3
Other	(3)	(7)	2	—	1
Other, net	$ (43)	$ (76)	$ 3	$ 2	$ 7

Six Months Ended June 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory Agreement Units	$ 110	$ 110	$ —	$ —	$—
Non-Regulatory Agreement Units	67	67	—	—	—
Net unrealized losses on decommissioning trust funds					
Regulatory Agreement Units	150	150	—	—	—
Non-Regulatory Agreement Units	30	30	—	—	—
Net unrealized income on pledged assets					
Zion Station decommissioning	38	38	—	—	—
Regulatory offset to decommissioning trust fund-related activities(b)	(245)	(245)	—	—	—
Total decommissioning-related activities	150	150	—	—	—
Investment income	10	—	—	2	6
Long-term lease income	15	—	—	—	—
Interest income related to uncertain income tax positions	14	—	1	—	—
Credit facility termination fees	(42)	(42)	—	—	—
AFUDC — Equity	7	—	1	2	6
Other	(2)	(5)	5	1	1
Other, net	$ 152	$ 103	$ 7	$ 5	$ 13

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.
(b) Includes the elimination of NDT fund-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.

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

Supplemental Cash Flow Information

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

Six Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$ 942	$ 402	$ 275	$ 109	$ 128
Regulatory assets	112	—	62	4	47
Amortization of intangible assets, net	22	22	—	—	—
Amortization of energy contract assets and liabilities(a)	306	344	—	—	—
Nuclear fuel(a)	454	454	—	—	—
ARO accretion(b)	136	136	—	—	—
Total depreciation, amortization, accretion and depletion	$ 1,972	$ 1,358	$ 337	$ 113	$ 175

Six Months Ended June 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$ 806	$ 343	$ 262	$ 102	$ 123
Regulatory assets	56	—	38	5	27
Amortization of intangible assets, net	14	14	—	—	—
Amortization of energy contract assets and liabilities(a)	485	532	—	—	—
Nuclear fuel(a)	419	419	—	—	—
ARO accretion(b)	115	115	—	—	—
Total depreciation, amortization, accretion and depletion	$ 1,895	$ 1,423	$ 300	$ 107	$ 150

(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.

Six Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 409	$ 173	$ 154	$ 21	$ 27
Loss in equity method investments	30	30	—	—	—
Provision for uncollectible accounts	55	10	4	27	14
Stock-based compensation costs	70	—	—	—	—
Other decommissioning-related activity(a)	(62)	(62)	—	—	—
Energy-related options(b)	65	65	—	—	—
Amortization of regulatory asset related to debt costs	6	—	5	1	—
Amortization of rate stabilization deferral	29	—	—	—	29
Amortization of debt fair value adjustment	(22)	(22)	—	—	—
Discrete impacts from EIMA(c)	(126)	—	(126)	—	—
Amortization of debt costs	8	5	2	1	—
Merger integration costs(d)	(6)	—	—	—	(6)
Impairment of investments in direct financing leases(e)	14	—	—	—	—
Increase in inventory reserve	13	13	—	—	—
Impairment charges(f)	110	110	—	—	—
Other	(17)	(7)	—	—	(3)
Total other non-cash operating activities	$ 576	$ 315	$ 39	$ 50	$ 61

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

Six Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ (24)	$ —	$ (61)	$ 19	$ 18
Other regulatory assets and liabilities	3	—	(28)	(5)	(82)
Other current assets	(123)	(134)	2	(62)	99
Other noncurrent assets and liabilities	277	(34)	259(g)	(1)	28
Total changes in other assets and liabilities	$ 133	$ (168)	$ 172	$ (49)	$ 63
Non-cash investing and financing activities:					
Consolidated VIE dividend to non-controlling interest	$ 63	$ 63	$ —	$ —	$ —
Indemnification of like-kind exchange position(h)	—	—	174	—	—
Total non-cash investing and financing activities:	$ 63	$ 63	$ 174	$ —	$ —

Six Months Ended June 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 400	$ 175	$ 137	$ 26	$ 32
Provision for uncollectible accounts	60	(1)	21	26	17
Stock-based compensation costs	56	—	—	—	—
Other decommissioning-related activity(a)	(62)	(62)	—	—	—
Energy-related options(b)	64	64	—	—	—
Amortization of regulatory asset related to debt costs	9	—	7	1	1
Amortization of rate stabilization deferral	15	—	—	—	25
Amortization of debt fair value adjustment	(26)	(11)	—	—	—
Discrete impacts from EIMA(c)	69	—	69	—	—
Amortization of debt costs	—	—	2	—	—
Merger-related commitments(i)	188	35	—	—	28
Severance cost	119	30	—	7	—
Loss in equity method investments	79	79	—	—	—
Other	(12)	9	5	6	(3)
Total other non-cash operating activities	$ 959	$ 318	$ 241	$ 66	$100
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ (37)	$ —	$ (58)	$ 18	$ 2
Other regulatory assets and liabilities	(514)	—	(39)	12	(28)
Other current assets	190	(97)	(1)	(110)	55
Other noncurrent assets and liabilities	(12)	(77)	(6)	(7)	14
Total changes in other assets and liabilities	$ (373)	$ (174)	$ (104)	$ (87)	$ 43
Non-cash investing and financing activities:					
Merger with Constellation, common stock issued	$7,365	$ 5,272	$ —	$ —	$ —
Total non-cash investing and financing activities:	$7,365	$ 5,272	$ —	$ —	$ —

(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.

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

(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 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.

DOE Smart Grid Investment Grant (Exelon, PECO and BGE). For the six months ended June 30, 2013, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $41 million, $12 million and $29 million, respectively, and reimbursements of $50 million, $16 million and $34 million, respectively, related to PECO's and BGE's DOE SGIG programs. For the six months ended June 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 $52 million, $34 million and $18 million, respectively, and reimbursements of $65 million, $46 million and $19 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 June 30, 2013 and December 31, 2012.

June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$12,905(a)	$ 6,521(a)	$3,035	$2,874	$2,656
Accounts receivable:					
Allowance for uncollectible accounts	306	85	68	115	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 $2,220 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 $23 million as of June 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 June 30, 2013 of $21 million consists of $1 million, $4 million and $16 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 June 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.

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

- 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, 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.

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

Three Months Ended June 30, 2013 and 2012

	Generation(a)	ComEd	PECO	BGE	Other(b)	Intersegment Eliminations	Exelon
Total revenues(c):							
2013	$ 4,070	$ 1,080	$ 672	$ 653	$ 297	$ (631)	$ 6,141
2012	3,765	1,281	715	616	363	(774)	5,966
Intersegment revenues:							
2013	$ 329	$ —	$ —	$ 4	$ 298	$ (631)	$ —
2012	408	1	1	2	362	(774)	—
Net income (loss):							
2013	$ 328	$ 96	$ 78	$ 25	$ (30)	$ —	$ 497
2012	165	42	80	16	(14)	—	289
Total assets:							
June 30, 2013	$ 39,678	$23,349	$9,407	$7,968	$ 9,763	$ (11,745)	$78,420
December 31, 2012	40,681	22,905	9,353	7,506	10,432	(12,316)	78,561

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

(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 June 30, 2013 include revenue from sales to PECO of $97 million and sales to BGE of $99 million in the Mid-Atlantic region, and sales to ComEd of $121 million in the Midwest region, net of $10 million related to the unrealized mark-to-market gains related to the ComEd swap, which eliminate upon consolidation. For the three months ended June 30, 2012 intersegment revenues for Generation include revenue from sales to PECO of $125 million and sales to BGE of $84 million in the Mid-Atlantic region, and sales to ComEd of $203 million in the Midwest region, net of $4 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 June 30, 2013 and 2012, utility taxes of $18 million and $19 million, respectively, are included in revenues and expenses for Generation. For the three months ended June 30, 2013 and 2012, utility taxes of $56 million and $54 million, respectively, are included in revenues and expenses for ComEd. For the three months ended June 30, 2013 and 2012, utility taxes of $31 million and $34 million, respectively, are included in revenues and expenses for PECO. For the three months ended June 30, 2013 and 2012, utility taxes of $19 million and $19 million, respectively, are included in revenues and expenses for BGE.

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	$ 1,220	$ 9	$ 1,229	$ 1,433	$ (28)	$ 1,405
Midwest	1,076	(5)	1,071	1,193	8	1,201
New England	209	(20)	189	296	32	328
New York	175	(1)	174	166	(22)	144
ERCOT	319	(4)	315	412	1	413
Other Regions(b)	246	(6)	240	219	25	244
Total Revenues for Reportable Segments	$ 3,245	$ (27)	$ 3,218	$ 3,719	$ 16	$ 3,735
Other(c)	825	27	852	46	(16)	30
Total Generation Consolidated Operating Revenues	$ 4,070	$ —	$ 4,070	$ 3,765	$ —	$ 3,765

(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 $234 million and $534 million, for the three months ended June 30, 2013 and 2012, respectively, and elimination of intersegment revenues.

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

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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	$ 770	$ (2)	$ 768	$ 911	$ (28)	$ 883
Midwest	687	(3)	684	756	8	764
New England	85	(35)	50	28	32	60
New York	—	14	14	61	(22)	39
ERCOT	143	(31)	112	118	1	119
Other Regions(b)	111	(52)	59	9	25	34
Total Revenues net of purchased power and fuel expense for Reportable Segments	$ 1,796	$ (109)	$1,687	$ 1,883	$ 16	$1,899
Other(c)	328	109	437	30	(16)	14
Total Generation Revenues net of purchased power and fuel expense	$ 2,124	$ —	$2,124	$ 1,913	$ —	$1,913

(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 $167 million and $414 million for the three months ended June 30, 2013 and 2012, respectively.

Six Months Ended June 30, 2013 and 2012

	Generation(a)	ComEd	PECO	BGE(b)	Other(c)	Intersegment Eliminations	Exelon
Total revenues(d):							
2013	$ 7,603	$2,239	$1,567	$1,533	$ 615	$ (1,334)	$12,223
2012	6,508	2,670	1,590	668	714	(1,494)	10,656
Intersegment revenues(e):							
2013	$ 710	$ 1	$ —	$ 8	$ 615	$ (1,334)	$ —
2012	774	1	2	3	715	(1,494)	1
Net income (loss):							
2013	$ 310	$ 14	$ 200	$ 106	$ (132)	$ —	$ 498
2012	332	129	177	(49)	(99)	—	490

(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 six months ended June 30, 2013 include revenue from sales to PECO of $238 million and sales to BGE of $212 million in the Mid-Atlantic region, and sales to ComEd of $266 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 six months ended June 30, 2012 intersegment revenues for Generation include revenue from sales to PECO of $235 million in the Mid-Atlantic region and sales to BGE of $103 million in the Mid-Atlantic region, and sales to ComEd of $451 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) Amounts represent activity recorded at BGE from March 12, 2012, the closing date of the merger, through June 30, 2012.

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

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

(d) For the six months ended June 30, 2013 and 2012, utility taxes of $39 million and $32 million, respectively, are included in revenues and expenses for Generation. For the six months ended June 30, 2013 and 2012, utility taxes of $117 million and $115 million, respectively, are included in revenues and expenses for ComEd. For the six months ended June 30, 2013 and 2012, utility taxes of $64 million and $68 million, respectively, are included in revenues and expenses for PECO. For the six months ended June 30, 2013 and period of March 12, 2012 through June 30, 2012, utility taxes of $41 million and $22 million, respectively, are included in revenues and expenses for BGE.

(e) The intersegment profit associated with Generation's sale of AECs to PECO is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. See Note 3 — Regulatory Matters of the Exelon 2012 Form 10-K for additional information on AECs. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations.

Generation total revenues (six months ended):

	2013			2012		
	Revenues from external customers(a)	Intersegment revenues	Total Revenues	Revenues from external customers(a)	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 2,551	$ 1	$ 2,552	$ 2,404	$ (33)	$ 2,371
Midwest	2,257	2	2,259	2,407	12	2,419
New England	600	(8)	592	386	35	421
New York	350	(7)	343	211	(24)	187
ERCOT	612	(4)	608	541	—	541
Other Regions(b)	429	36	465	294	29	323
Total Revenues for Reportable Segments	$ 6,799	$ 20	$ 6,819	$ 6,243	$ 19	$ 6,262
Other(c)	804	(20)	784	265	(19)	246
Total Generation Consolidated Operating Revenues	$ 7,603	$ —	$ 7,603	$ 6,508	$ —	$ 6,508

(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 $478 million and $686 million, for the six months ended June 30, 2013 and 2012, respectively, and elimination of intersegment revenues.

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

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

	2013			2012		
	RNF from external customers(a)	Intersegment RNF	Total RNF	RNF from external customers(a)	Intersegment RNF	Total RNF
Mid-Atlantic	$ 1,622	$ (10)	$1,612	$ 1,686	$ (33)	$1,653
Midwest	1,397	4	1,401	1,569	12	1,581
New England	103	(23)	80	64	35	99
New York	(16)	8	(8)	71	(24)	47
ERCOT	255	(42)	213	153	—	153
Other Regions(b)	122	(17)	105	19	29	48
Total Revenues net of purchased power and fuel expense for Reportable Segments	$ 3,483	$ (80)	$3,403	$ 3,562	$ 19	$3,581
Other(c)	6	80	86	50	(19)	31
Total Generation Revenues net of purchased power and fuel expense	$ 3,489	$ —	$3,489	$ 3,612	$ —	$3,612

(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 $341 million and $537 million, for the six months ended June 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.

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Executive Overview

Financial Results. The following consolidated financial results reflect the results of Exelon for the three and six months ended June 30, 2013 compared to the same period in 2012. The financial results for the six months ended June 30, 2012 only include the operations of Constellation and BGE from the date of the merger with Constellation, March 12, 2012, through June 30, 2012. All amounts presented below are before the impact of income taxes, except as noted.

	Three Months Ended June 30, 2013						2012	Favorable (Unfavorable) Variance
	Generation	ComEd	PECO	BGE	Other	Exelon	Exelon	
Operating revenues	$ 4,070	$1,080	$672	$653	$(334)	$6,141	$5,966	$ 175
Purchased power and fuel	1,946	248	258	288	(321)	2,419	2,606	187
Revenue net of purchased power and fuel(a)	2,124	832	414	365	(13)	3,722	3,360	362
Other operating expenses								
Operating and maintenance	1,189	359	181	160	3	1,892	1,841	(51)
Depreciation and amortization	210	170	56	82	15	533	494	(39)
Taxes other than income	101	71	39	54	6	271	254	(17)
Total other operating expenses	1,500	600	276	296	24	2,696	2,589	(107)
Equity in loss of unconsolidated affiliates	(21)	—	—	—	—	(21)	(57)	36
Operating income (loss)	603	232	138	69	(37)	1,005	714	291
Other income and (deductions)								
Interest expense, net	(93)	(76)	(28)	(32)	(23)	(252)	(256)	4
Other, net	(33)	6	—	4	6	(17)	(43)	26
Total other income and (deductions)	(126)	(70)	(28)	(28)	(17)	(269)	(299)	30
Income (loss) before income taxes	477	162	110	41	(54)	736	415	321
Income taxes	149	66	32	16	(24)	239	126	(113)
Net income (loss)	328	96	78	25	(30)	497	289	208
Net (loss) income attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	(2)	—	6	3	—	7	3	(4)
Net income (loss) attributable to common shareholders	$ 330	$ 96	$ 72	$ 22	$ (30)	$ 490	$ 286	$ 204

	Six Months Ended June 30, 2013 Generation	ComEd	PECO	BGE	Other	Exelon	2012 Exelon	Favorable (Unfavorable) Variance
Operating revenues	$ 7,603	$2,239	$1,567	$1,533	$(719)	$12,223	$10,656	$ 1,567
Purchased power and fuel	4,114	630	664	713	(721)	5,400	4,371	(1,029)
Revenue net of purchased power and fuel(a)	3,489	1,609	903	820	2	6,823	6,285	538
Other operating expenses								
Operating and maintenance	2,302	687	369	303	(5)	3,656	3,809	153
Depreciation and amortization	424	337	113	175	27	1,076	876	(200)
Taxes other than income	194	145	80	109	20	548	448	(100)
Total other operating expenses	2,920	1,169	562	587	42	5,280	5,133	(147)
Equity in loss of unconsolidated affiliates	(30)	—	—	—	—	(30)	(79)	49
Operating income (loss)	539	440	341	233	(40)	1,513	1,073	440
Other income and (deductions)								
Interest expense, net	(176)	(429)	(57)	(66)	(148)	(876)	(451)	(425)
Other, net	95	11	3	9	37	155	152	3
Total other income and (deductions)	(81)	(418)	(54)	(57)	(111)	(721)	(299)	(422)
Income (loss) before income taxes	458	22	287	176	(151)	792	774	18
Income taxes	148	8	87	70	(19)	294	284	(10)
Net income (loss)	310	14	200	106	(132)	498	490	8
Net (loss) income attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	(1)	—	7	6	—	12	4	(8)
Net income (loss) attributable to common shareholders	$ 311	$ 14	$ 193	$ 100	$(132)	$ 486	$ 486	$ —

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

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. Exelon's net income attributable to common shareholders was $490 million for the three months ended June 30, 2013 as compared to net income attributable to common shareholders of $286 million for the three months ended June 30, 2012, and diluted earnings per average common share were $ 0.57 for the three months ended June 30, 2013 as compared to $0.33 for the three months ended June 30, 2012.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $362 million for the three months ended June 30, 2013 as compared to the same period in 2012. The year-over-year increase in operating revenue net of purchased power and fuel expense was primarily due to the following favorable factors:

- Increase in Generation's mark-to-market gains from economic hedging activities of $228 million;

- Decrease in Generation's amortization expense for the acquired energy contracts recorded at fair value at the merger date of $247 million;
- Increase in ComEd's revenue net of purchased power and fuel expense of $138 million primarily due to the ICC's May 2012 Order, increased distribution revenue due to recovery of increased costs and capital investment pursuant to the formula rate under EIMA and the 2013 enactment of Senate Bill 9, partially offset by unfavorable weather; and
- Increase in BGE's revenue net of purchased power and fuel expense of $34 million primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective February 23, 2013 in accordance with the 2012 MDPSC approved electric and natural gas distribution rate case order.

The year-over-year increase in operating revenue net of purchased power and fuel expense was partially offset by the following unfavorable factors:

- Decrease in Generation's electric revenue net of purchased power and fuel expense of $212 million primarily due to lower realized energy prices, lower capacity revenue, lower load volume and increased nuclear fuel expense, partially offset by lower energy supply costs as a result of the integration of the energy generation and load serving businesses following the merger; and
- Reduced margin at Generation of $57 million in 2013 associated with the Maryland Clean Coal assets that were sold in November 2012 and lost compensation from the FERC-approved reliability-must-run program with PJM for retired fossil generating assets that expired on May 31, 2012.

Operating and maintenance expense increased by $51 million for the three months ended June 30, 2013 as compared to the same period in 2012 primarily due to the following unfavorable factors:

- Long-lived asset impairment and related charges of $106 million in the second quarter of 2013, primarily related to Generation's cancellation of nuclear uprate projects; and
- Increase in labor, other benefits, contracting and materials costs of $27 million due to the impact of inflation across all operating companies, partially offset by realized merger synergy savings at Exelon's corporate operations and shared service entities and at Generation.

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

- Decrease in Constellation merger and integration costs of $32 million; and
- Decrease in operating and maintenance expense associated with the generating assets retired or divested during 2012 of $42 million.

Depreciation and amortization expense increased by $39 million primarily due to ongoing capital expenditures across the operating companies, the completion of wind and solar facilities placed into service in the second half of 2012 and in 2013 at Generation and increased regulatory asset amortization related to higher MGP remediation expenditures and higher costs for energy efficiency and demand response programs at ComEd and BGE, respectively.

Equity in loss of unconsolidated affiliates decreased by $36 million primarily due to higher net income generated from Generation's equity investment in CENG in the second quarter of 2013 compared to the same period in 2012 and lower amortization of the basis difference of Generation's ownership interest in CENG recorded at fair value in connection with the merger.

Exelon's effective income tax rates for the three months ended June 30, 2013 and 2012 were 32.5% and 30.4%, respectively. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. Exelon's net income attributable to common shareholders was $486 million for the six months ended June 30, 2013 as compared to net income attributable to common shareholders of $486 million for the six months ended June 30, 2012, and diluted earnings per average common share were $0.57 for the six months ended June 30, 2013 as compared to $0.62 for the six months ended June 30, 2012.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $538 million for the six months ended June 30, 2013 as compared to the same period in 2012. The year-over-year increase in operating revenue net of purchased power and fuel expense was primarily due to the following favorable factors:

- Increase in BGE's revenue net of purchased power and fuel expense of $504 million, primarily as a result of the inclusion of BGE's results for the full period in 2013 and the impact of the new electric and natural gas distribution rates charged to customers that became effective February 23, 2013 in accordance with the 2012 MDPSC approved electric and natural gas distribution rate case order;
- Increase in Generation's net margin of $174 million on other activities, including proprietary trading, retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of customer sited solar facilities, primarily due to the addition of Constellation;
- Decrease in Generation's amortization expense for the acquired energy contracts recorded at fair value at the merger date of $196 million;
- Increase in ComEd's revenue net of purchased power and fuel expense of $147 million primarily due to the ICC's May 2012 Order and increased distribution revenue due to recovery of increased costs and capital investment pursuant to the formula rate under EIMA; and
- Increase in PECO's revenue net of purchased power and fuel expense of $20 million primarily due to favorable weather conditions, partially offset by lower realized prices.

The year-over-year increase in operating revenue net of purchased power and fuel expense was partially offset by the following unfavorable factors:

- Decrease in Generation's mark-to-market gains from economic hedging activities of $235 million;
- Decrease in Generation's electric revenue net of purchased power and fuel expense of $178 million primarily due to lower realized energy prices, lower capacity revenue, lower load volume and increased nuclear fuel expense, partially offset by lower energy supply costs as a result of the integration of the energy generation and load serving businesses following the merger; and
- Reduced margin at Generation of $80 million in 2013 associated with the Maryland Clean Coal assets that were sold in November 2012 and lost compensation on the reliability-must-run program with PJM for retired fossil generating assets that expired on May 31, 2012.

Operating and maintenance expense decreased by $153 million for the six months ended June 30, 2013 as compared to the same period in 2012 primarily due to the following favorable factors:

- Costs incurred in March 2012 of $216 million as part of the Maryland order approving the merger and of $195 million associated with a settlement with the FERC; and
- Decrease in Constellation merger and integration costs of $152 million in 2013.

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

- Increase in labor, other benefits, contracting and materials costs of $264 million and increase in pension and non-pension postretirement benefit expenses of $18 million, primarily due to the addition of BGE and Constellation for the full period in 2013; and

- Long-lived asset impairment and related charges of $127 million in 2013, primarily related to Generation's cancellation of nuclear uprate projects.

Depreciation and amortization expense increased by $200 million primarily due to higher plant balances resulting from the addition of BGE's and Constellation's plant balances in 2012, ongoing capital expenditures across the operating companies, the completion of wind and solar facilities placed into service in the second half of 2012 and in 2013 at Generation and increased regulatory asset amortization related to higher MGP remediation expenditures and higher costs for energy efficiency and demand response programs at ComEd and BGE, respectively.

Equity in loss of unconsolidated affiliates decreased $49 million primarily due to higher net income generated from Generation's equity investment in CENG in 2013 compared to the same period in 2012 and lower amortization of the basis difference of Generation's ownership interest in CENG recorded at fair value in connection with the merger.

Interest expense increased by $425 million primarily due to an increase in interest expense at ComEd related to the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013, an increase in debt obligations as a result of the merger and an increase in debt issued at Generation in June 2012.

Exelon's effective income tax rates for the six months ended June 30, 2013 and June 30, 2012 were 37.1% and 36.7%, respectively. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

For further detail regarding the financial results for the three and six months ended June 30, 2013, including explanation of the non-GAAP measure revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

Adjusted (non-GAAP) Operating Earnings. Exelon's adjusted (non-GAAP) operating earnings for the three months ended June 30, 2013 were $ 454 million, or $ 0.53 per diluted share, compared with adjusted (non-GAAP) operating earnings of $ 522 million, or $ 0.61 per diluted share, for the same period in 2012. Exelon's adjusted (non-GAAP) operating earnings for the six months ended June 30, 2013 were $1,056 million, or $1.23 per diluted share, compared with adjusted (non-GAAP) operating earnings of $1,125 million, or $1.44 per diluted share, for the same period in 2012. In addition to net income attributable to common shareholders, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

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The following table provides a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the three and six months ended June 30, 2013 as compared to the same period in 2012:

	Three Months Ended June 30,			
	2013		2012	
(All amounts after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$ 490	$ 0.57	$ 286	$ 0.33
Mark-to-Market Impact of Economic Hedging Activities(a)	(253)	(0.30)	(123)	(0.15)
Unrealized Losses Related to NDT Fund Investments(b)	22	0.03	19	0.02
Plant Retirement and Divestitures(c)	—	—	(1)	—
Constellation Merger and Integration Costs(d)	15	0.02	67	0.08
Amortization of Commodity Contract Intangibles(e)	115	0.13	281	0.33
Amortization of the Fair Value of Certain Debt(f)	(4)	—	(3)	—
Non-Cash Remeasurement of State Deferred Income Taxes(g)	—	—	(4)	—
Long-Lived Asset Impairment(h)	69	0.08	—	—
Adjusted (non-GAAP) Operating Earnings	$ 454	$ 0.53	$ 522	$ 0.61

	Six Months Ended June 30,			
	2013		2012	
(All amounts after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$ 486	$ 0.57	$ 486	$ 0.62
Mark-to-Market Impact of Economic Hedging Activities(a)	(18)	(0.02)	(167)	(0.21)
Unrealized Gains Related to NDT Fund Investments(b)	(14)	(0.02)	(17)	(0.02)
Plant Retirement and Divestitures(c)	(13)	(0.02)	7	0.01
Constellation Merger and Integration Costs(d)	43	0.05	180	0.23
Amortization of Commodity Contract Intangibles(e)	232	0.27	358	0.46
Amortization of the Fair Value of Certain Debt(f)	(7)	(0.01)	(3)	—
Non-Cash Remeasurement of State Deferred Income Taxes(g)	—	—	(121)	(0.16)
Long-Lived Asset Impairment(h)	82	0.10	—	—
Remeasurement of Like-Kind Exchange Tax Position(i)	265	0.31	—	—
Other Acquisition Costs(j)	—	—	3	—
Maryland Commitments(k)	—	—	227	0.29
FERC Settlement(l)	—	—	172	0.22
Adjusted (non-GAAP) Operating Earnings	$1,056	$ 1.23	$1,125	$ 1.44

(a) Reflects the impact of gains for the three and six months ended June 30, 2013 (net of taxes of $(163) million and $(13) million, respectively) and for the three and six months ended June 30, 2012 (net of taxes of $(81) million and $(109) million, respectively), on Generation's economic hedging activities. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(b) Reflects the impact of unrealized (gains) losses for the three and six months ended June 30, 2013 (net of taxes of $41 million and $(27) million, respectively) and for the three and six months ended June 30, 2012 (net of taxes of $37 million and $(46) million, respectively) on Generation's NDT fund investments for Non-Regulatory Agreement Units. See Note 13 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Reflects the impacts associated with the sale or retirement of generating stations for the six months ended June 30, 2013 (net of taxes of $5 million) and for the three and six months ended June 30, 2012 (net of taxes of $1 million and $3 million, respectively). See "Results of Operations — Generation" for additional detail related to the generating station retirements.

(d) Reflects certain costs incurred for the three and six months ended June 30, 2013 (net of taxes of $10 million and $4 million, respectively) and for the three and six months ended June 30, 2012 (net of taxes of $44 million and $76 million, respectively) associated with the Constellation merger, including transaction costs, employee-related expenses (e.g. severance, retirement, relocation and retention bonuses) integration initiatives and certain pre-acquisition contingencies, partially offset in 2013 by a one-time benefit pursuant to the BGE 2012 electric and gas distribution rate case order for the recovery of previously incurred integration costs. See Note 4 — Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

(e) Reflects the non-cash impact for the three and six months ended June 30, 2013 and 2012 (net of taxes of $73 million and $148 million, respectively) and for the three and six months ended June 30, 2012 (net of taxes of $183 million and $234 million, respectively) of the amortization of intangible assets, net, related to commodity contracts recorded at fair value at the Constellation merger date. See Note 4 — Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

(f) Reflects the non-cash amortization of certain debt for the three and six months ended June 30, 2013 (net of taxes of $(3) million and $(5) million, respectively) and for the three and six months ended June 30, 2012 (net of taxes of $(2) million and $(2) million, respectively) recorded at fair value at the merger date which debt was retired in the second quarter of 2013. See Note 4 — Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

(g) Reflects the non-cash impacts of the remeasurement of state deferred income taxes as a result of the Constellation merger. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

(h) Reflects 2013 impairment and related charges to earnings for the three and six months ended June 30, 2013 (net of taxes of $44 million and $53 million, respectively) primarily related to Generation's cancellation of nuclear uprate projects.

(i) Reflects a non-cash charge to earnings for the six months ended June 30, 2013 (net of taxes of $102 million) resulting from the first quarter 2013 remeasurement of a like-kind exchange tax position taken on ComEd's 1999 sale of fossil generating assets. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

(j) Reflects certain costs incurred for the six months ended June 30, 2012 (net of taxes of $2 million) associated with various acquisitions.

(k) Reflects costs incurred for the three months ended June 30, 2012 associated with the Constellation merger (net of taxes of $101 million) as part of the Maryland order approving the merger transaction. See Note 4 — Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

(l) Reflects costs incurred for the six months ended June 30, 2012 (net of taxes of $23 million) as part of a settlement with the FERC to resolve a dispute related to Constellation's pre-merger hedging and risk management transactions. See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

As discussed above, Exelon has incurred and will continue to incur costs associated with the Constellation merger including, meeting the various commitments set forth by regulators and agreed-upon with other interested parties as part of the merger approval process, and integrating the former Constellation businesses into Exelon.

For the three and six months ended June 30, 2013, expense has been recognized for costs incurred to achieve the merger as follows:

	Pre-tax Expense Three Months Ended June 30, 2013				
Merger and Integration Costs:	**Generation(a)**	**ComEd**	**PECO**	**BGE(a)**	**Exelon(a)**
Employee-Related(b)	7	—	—	—	7
Other(c)	13	—	2	1(d)	18
Total	$ 20	$ —	$ 2	$ 1	$ 25

	Pre-tax Expense Six Months Ended June 30, 2013				
Merger and Integration Costs:	**Generation(a)**	**ComEd**	**PECO**	**BGE(a)**	**Exelon(a)**
Employee-Related(b)	13	—	1	—	14
Other(c)	30	—	4	(5)	32
Total	$ 43	$ —	$ 5	$ (5)	$ 46

Merger and Integration Costs:	Pre-tax Expense Three Months Ended June 30, 2012 Generation(a)	ComEd	PECO	BGE(a)	Exelon(a)
Transaction(e)	—	—	—	—	2
Employee-Related(b)	39	—	2	—	43
Other(c)	55	—	2	2(d)	66
Total	$ 94	$ —	$ 4	$ 2	$ 111

Merger and Integration Costs:	Pre-tax Expense Six Months Ended June 30, 2012 Generation(a)	ComEd	PECO	BGE(a)	Exelon(a)
Transaction(e)	—	—	—	—	52
Maryland Commitments	35	—	—	139	328
Employee-Related(b)	86	—	7	—	101
Other(c)	83	2	4	3	103
Total	$ 204	$ 2	$ 11	$ 142	$ 584

(a) For Exelon, Generation and BGE, includes the operations of the acquired businesses for the six months ended June 30, 2013 and from the date of the merger, March 12, 2012, through June 30, 2012.
(b) Costs primarily for employee severance, pension and OPEB expense and retention bonuses. ComEd established regulatory assets of $0 million and $4 million during the three months ended June 30, 2013 and June 30, 2012 and $1 million and $16 million during the six months ended June 30, 2013 and June 30, 2012, respectively. For ComEd, the majority of these costs are expected to be recovered over a five-year period. ComEd and BGE established a regulatory asset of $16 million and $18 million, respectively, during the six months ended June 30, 2012, for severance benefit costs and the majority of these costs will be recovered over a five-year period. These costs are not included in the table above.
(c) Costs to integrate Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. ComEd established a regulatory asset of $4 million and $3 million during the three months ended June 30, 2013 and 2012 and $7 million and $7 million during the six months ended June 30, 2013 and June 30, 2012, respectively, for certain other merger and integration costs, which are not included in the table above. BGE established a regulatory asset of $2 million during the six months June 30, 2013 for certain other merger integration costs, which are not included in the table above.
(d) BGE established a regulatory asset of $6 million at June 30, 2013 for certain 2012 other merger integration costs as part of the 2013 electric and gas distribution rate case order.
(e) External, third-party costs paid to advisors, consultants, lawyers and other experts to assist in the due diligence and regulatory approval processes and in the closing of the transaction.

As of June 30, 2013, Exelon projects incurring total additional merger-related expenses, primarily in 2013, of approximately $95 million.

Pursuant to the conditions set forth by the MDPSC in its approval of the merger transaction, Exelon committed to provide a package of benefits to BGE customers, and make certain investments in the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of more than $1 billion. The direct investment estimate includes $95 million to $120 million for the requirement to cause construction of a headquarters building in Baltimore for Generation’s competitive energy businesses. On March 20, 2013, Generation signed a twenty year lease agreement that is contingent upon the developer obtaining financing for the construction of the building. Once the financing conditions are met, construction of the building will commence and is expected to be ready for occupancy in 2 years. The direct investment estimate also includes $625 million in expenditures relating to the development of 285-300 MW of new electric generation facilities in Maryland (expected to be completed over the next ten years).

Exelon's Strategy and Outlook for the remainder of 2013 and Beyond

Exelon's value proposition and competitive advantage come from its scope and scale across the energy value chain and its core strengths of operational excellence and financial discipline.

On March 12, 2012, the Exelon and Constellation merger was completed. The merger creates incremental strategic value by matching Exelon's clean generation fleet with Constellation's leading customer-facing platform, as well as creating economies of scale through expansion across the energy value chain. Exelon supports customer switching to alternative electric generation suppliers and the addition of Constellation's competitive retail operations provides another outlet for Exelon to grow its business in competitive markets.

Generation's nuclear, fossil fuel, hydroelectric and renewable energy electricity generation strategy is to pursue opportunities that provide generation to load matching and that diversify the generation fleet by expanding its regional and technological footprint. Generation leverages its energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in spot markets. Generation's customer facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation's presence in well-developed energy markets, its integrated hedging strategy mitigating short-term market volatility, and its low cost nuclear generating fleet operating consistently at high capacity factors, position it well to succeed in competitive energy markets.

Exelon's utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of best practices to achieve improved operational and financial results.

Exelon's financial priorities are to maintain investment grade credit metrics at each of Exelon, Generation, ComEd, PECO and BGE, and to return value to Exelon's shareholders with a sustainable dividend throughout the energy commodity market cycle and through earnings growth from attractive investment opportunities.

In pursuing its strategies, Exelon has exposure to various market and financial risks, including the risk of price fluctuations in the power markets. Power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular, the prices of natural gas and coal, which drive the market prices that Generation can obtain for the output of its power plants' output, (2) the rate of expansion of subsidized low carbon generation in the markets in which Generation's output is sold, (3) the effects on energy demand of factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) the impacts of increased competition in the retail channel.

Power Markets

Price of Fuels. The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Since the third quarter of 2011, forward natural gas prices for 2013 and 2014 have declined significantly; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

Subsidized Generation. The rate of expansion of subsidized low carbon generation such as wind and solar energy in the markets in which Generation's output is sold can negatively impact wholesale power prices, and in turn, Generation's results of operations.

Various states have implemented or proposed legislation, regulations or other policies to subsidize new generation development which may result in artificially depressed wholesale energy and capacity prices. For example, on April 12, 2012, the MDPSC issued an order directing the Maryland electric utilities to enter into a 20-year contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW combined cycle gas turbine in Waldorf, Maryland, that it projected will be in commercial operation by June 1, 2015. CPV has subsequently extended that date. The CfD mandates that utilities (including BGE) pay (or receive) the difference between CPV's contract price and the revenues it receives for capacity and energy from clearing the unit in the PJM capacity market. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Similarly, in January 2011, New Jersey passed legislation that provides guaranteed cost recovery through a CfD for the development of up to 2,000 MWs of new base load or mid-merit generation, so long as it clears in PJM's capacity market. Three generation developers were chosen for the New Jersey CfD, for which contracts were executed in 2011 by the state's utilities under protest. Similarly, in Illinois, legislation has been debated for over four years that passed in the Senate and is currently being considered in the House which would require consumers to subsidize the development of an Integrated Gasification Combined Cycle plant by purchasing its electricity through 30 year power purchase agreements at prices significantly above market prices. A new version was recently introduced in the current Illinois General Assembly but its prospects are unclear at this time.

Exelon and others filed a complaint in federal district court challenging the constitutionality and other aspects of the New Jersey legislation. Similarly, Exelon and others are also challenging the selection of the three generation developers in New Jersey state court proceedings and the MDPSC actions in Maryland state court.

As required under their CfDs, two of the New Jersey generator developers and one in Maryland offered and cleared in PJM's capacity market auctions held in May 2012 and 2013. Given the state-required customer subsidy provided under their respective CfDs, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in these auctions and may continue to do so in future auctions to the detriment of Exelon's market driven position. A continuation of these state efforts, if successful and unabated by an effective minimum offer price rule (MOPR), could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish similar programs, which could substantially impact Exelon's market driven position and could have a significant effect on Exelon's financial results of operations, financial position and cash flows.

PJM's capacity market rules include a MOPR, which is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. However, as described above, Exelon does not believe that the existing MOPR will work effectively with respect to generator developers who have a state-sponsored subsidy and has concerns with certain other aspects of PJM's rules related to the capacity auction. Accordingly, Exelon is working with other market 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.

Energy Demand. The continued tepid economic environment and growing energy efficiency initiatives have limited the demand for electricity across the Exelon utilities. ComEd is projecting load volumes to remain essentially flat in 2013 compared to 2012, while PECO and BGE are projecting an increase (decrease) of 0.5% and (1.0%), respectively, in 2013 compared to 2012.

Retail Competition. Generation's retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. Recently, sustained low forward natural gas and power prices and low market volatility have caused retail competitors to aggressively pursue market share, and wholesale generators (including Generation) to use their retail operations to hedge generation output. These factors have adversely affected overall gross margins and profitability in Generation's retail operations.

Strategic Policy Alignment

Exelon routinely reviews its hedging policy, dividend policy, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices, and the impacts of hypothetical credit downgrades.

Exelon's Board of Directors declared the first quarter 2013 dividend of $0.525 per share, and in response to low forward energy prices and weaker financial expectations, among other factors, Exelon's Board of Directors approved a revised dividend policy going forward. The first quarter dividend was paid on March 8, 2013 to shareholders of record on February 19, 2013 and was based on Exelon's previous dividend of $2.10 per share on an annualized basis. The second quarter dividend is based on Exelon's new dividend policy of $0.31 per share quarterly dividend ($1.24 per share on an annualized basis). Consistent with past practice, all future quarterly dividends require approval by Exelon's Board of Directors.

Continuation of recent power price volatility and demand trends could adversely affect the Registrants' ability to fund discretionary uses of cash such as growth projects and dividends. In addition, economic conditions may no longer support the continued operation of certain generating facilities, which could adversely affect Generation's results of operations through increased depreciation rates, impairment charges and accelerated future decommissioning costs.

Hedging Strategy

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2013 and 2014. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of June 30, 2013, the percentage of expected generation hedged for the major reportable segments was 96%-99%, 78%-81% and 41%-44% 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 of energy to ComEd, PECO and BGE relating to their respective retail load obligations. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures coal, oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2013 through 2017 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position. ComEd, PECO and BGE mitigate such exposure through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Growth Opportunities

Exelon is currently pursuing growth in both the utility and generation businesses focused primarily on smart meter and smart grid initiatives at the utilities and on renewables development and the nuclear uprate program at Generation. The utilities also anticipate making significant future investments in infrastructure modernization and improvement initiatives. Management continually evaluates growth opportunities aligned with Exelon's existing businesses in electric and gas distribution, electric transmission, generation, customer supply of electric and natural gas products and services, and natural gas exploration and production activities, leveraging Exelon's expertise in those areas.

Smart Meter and Smart Grid Initiatives.

ComEd's Smart Meter and Smart Grid Investments. ComEd plans to invest approximately $1.3 billion on smart meters and smart grid under EIMA, including $1.0 billion through the AMI Deployment Plan. On June 5, 2012, the ICC issued an interim order approving ComEd's accelerated AMI deployment plan consistent with the provisions of Senate Bill 9. The deployment plan provides for the installation of 4 million electric smart meters, including 60,000 meters to be installed by the end of 2013.

PECO's Smart Meter and Smart Grid Investments. In 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan, under which PECO will install more than 1.6 million smart meters. PECO plans to spend up to a total of $595 million and $120 million on its smart meter and smart grid infrastructure, respectively, of which $200 million will be funded by SGIG.

BGE Smart Grid Initiative. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million electric and gas smart meters at an expected total cost of approximately $480 million, before considering the $200 million SGIG for smart grid and other related initiatives.

See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Initiatives.

Generation Renewable Development. On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, Inc., which developed and will build, operate, and maintain the project. The first portion of the project began operations in December 2012, with four additional blocks coming online in the first half of 2013 and an expectation of full commercial operation in December 2013. Exelon has been informed by First Solar of issues relating to potential delays in the certification of certain components relating to the final two blocks of the project which could delay commercial operation of these two blocks until the first quarter of 2014. The delay, if any, would not have a material financial effect on Exelon. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020. The project has a 25-year PPA, approved by the CPUC, with Pacific Gas & Electric Company for the full output of the plant. Upon completion, the facility will add 230 MWs to Generation's renewable generation fleet. Total capitalized costs for the facility are expected to be approximately $1.1 billion. Total capitalized costs incurred through June 30, 2013 were approximately $890 million. In addition, Generation constructed and placed into service 400MWs of additional wind generation in 2012 at a cost of $710 million and another 46MW will be added to Generation's wind portfolio in 2014 with the expansion of its Beebe project in Michigan.

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. 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 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 the 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.

Under the nuclear uprate program, Generation has placed into service projects representing 314 MWs of new nuclear generation at a cost of $891 million, which has been capitalized to property, plant and equipment on Exelon's and Generation's consolidated balance sheets. At June 30, 2013, Generation has capitalized $167 million to construction work in progress within property, plant and equipment for nuclear uprate projects expected to be placed in service by the end of 2016, consisting of 202 MWs of new nuclear generation, that are in the installation phase across four nuclear stations; Peach Bottom in Pennsylvania and Byron, Braidwood and Dresden in Illinois. The remaining spend associated with these projects is expected to be approximately $400 million through the end of 2016. Generation believes that it is probable that these projects will be completed. If a project is expected to not be completed as planned, previously capitalized costs will be reversed through earnings as a charge to operating and maintenance expense and interest.

Liquidity

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon, Generation, ComEd, PECO and BGE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.4 billion.

Exposure to Worldwide Financial Markets. Exelon has exposure to worldwide financial markets. The ongoing European debt crisis has contributed to the instability in global credit markets. Further disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of June 30, 2013, approximately 30%, or $2.5 billion, of the Registrants' aggregate total commitments were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.4 billion was available as of June 30, 2013. There were no borrowings under the Registrants' credit facilities as of June 30, 2013. See Note 11 – Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

Tax Matters

Exelon has exposure related to various uncertain tax positions which Exelon manages through planning and implementation of tax planning strategies. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information.

Environmental Legislative and Regulatory Developments.

Exelon supports the promulgation of certain environmental regulations by the U.S. EPA, including air, water and waste controls for electric generating units. See discussion below for further details. The air and waste regulations will have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and will likely result in the retirement of older, marginal facilities. Due to their low emission generation portfolios, Generation and CENG will not be significantly directly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. Congress that would prohibit or impede the U.S. EPA's rulemaking efforts. The timing of the consideration of such legislation is unknown.

Air Quality. In recent years, the U.S. EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act relating to NAAQS for conventional air pollutants (e.g., NO_x, SO_2 and particulate matter) as well as stricter technology requirements to control HAPs (e.g., acid gases, mercury and other heavy metals) from electric generation units. The U.S. EPA continues to review and update its NAAQS with a tightened particulate matter NAAQS issued in December 2012 and a review of the current 2008 ozone NAAQS that is expected to result in a proposed revision of the ozone NAAQS sometime in mid-2014. These updates will potentially result in more stringent emissions limits on fossil-fuel electric generating stations. There continues to be opposition among fossil-fuel generation owners to the potential stringency and timing of these air regulations.

In July 2011, the U.S. EPA published CSAPR and in June 2012, it issued final technical corrections. CSAPR requires 28 upwind states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in downwind states. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA had exceeded its authority in certain material aspects with respect to CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. Until the U.S. EPA re-issues CSAPR, Exelon cannot determine the impacts of the rule, including any that would impact power prices. In June 2013, the U.S. Supreme Court granted the U.S. EPA's petition to review the D.C. Circuit Court's CSAPR decision.

On December 16, 2011, the U.S. EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that owners of smaller, older, uncontrolled coal units will retire the units rather than make these investments. Coal units with existing controls that do not meet the MATS rule may need to upgrade existing controls or add new controls to comply. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies, or retire the units. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon has been granted permission by the Court to intervene in support of the rule. A decision by the Court may not occur until 2014. The outcome of the appeal, and its impact on power plant operators' investment and retirement decisions, is uncertain.

The cumulative impact of these air regulations could be to require power plant operators to expend significant capital to install pollution control technologies, including wet flue gas desulfurization technology for SO_2 and acid gases, and selective catalytic reduction technology for NO_x. 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 by January 1, 2015. In addition, Keystone already has SCR and Flue-gas desulfurization (FGD) controls in place.

On January 15, 2013, EPA issued a final rule for NSPS and National Emissions Standards for Hazardous Air Pollutants (NESHAP) for reciprocating internal combustion engines (RICE NESHAP/NSPS). The final rule allows diesel backup generators to operate for up to 100 hours annually under certain emergency circumstances without meeting emissions limitations, but requires units that operate over 15 hours to burn low sulfur fuel and report key engine information. The final rule eliminates after May 2014 the 50 hour exemption for peak shaving and other non-emergency demand response that was included in the proposed rule and, therefore, is not expected to result in additional megawatts of demand response to be bid into the PJM capacity auction.

In the absence of Federal legislation, the U.S. EPA is also moving forward with the regulation of GHG emissions under the Clean Air Act, including 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 that became effective January 2, 2011. Under the PSD regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case-by-case basis. On April 13, 2012, the U.S. EPA published proposed regulations for NSPS for GHG emissions from new fossil-fueled power plants greater than 25 MW that would require the plants to limit CO_2 emissions. The U.S. EPA will re-propose the regulations by September 2013. The U.S. EPA is also expected to propose by June 2014 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act, and to issue final regulations by June 2015. It is not yet known what the nature and impact of the final regulations will be.

Water Quality. Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. On March 28, 2011, the U.S. EPA issued a proposed rule, and is required under a Settlement Agreement to issue a final rule by November 4, 2013. The proposed rule does not require closed cycle cooling (e.g., cooling towers) as the best technology available, and also provides some flexibility in the use of cost-benefit considerations and site-specific factors. The proposed rule affords the state permitting agency wide discretion to determine the best technology available, which, depending on the site characteristics, could include closed cycle cooling, advanced screen technology at the intake, or retention of the current technology.

It is unknown at this time whether the final regulations will require closed-cycle cooling. The economic viability of Generation’s facilities 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.

Hazardous and Solid Waste. Under proposed U.S. EPA rules issued on June 21, 2010, coal combustion residuals (CCR) would be regulated for the first time under the RCRA. The U.S. EPA is considering several options, including classification of CCR either as a hazardous or non-hazardous waste, under RCRA. Under either option, the U.S. EPA's intention is the ultimate elimination of surface impoundments as a waste treatment process. For plants affected by the proposed rules, this would result in significant capital expenditures and variable operating and maintenance expenditures to convert to dry handling and disposal systems and installation of new waste water treatment facilities. Generation’s plants that would be affected by the proposed rules are Keystone and Conemaugh in Pennsylvania, which have on-site landfills that meet the requirements of Pennsylvania solid waste regulations for non-hazardous waste disposal. However, until the final rule is adopted, the impact on these facilities is unknown. The U.S. EPA has not announced a target date for finalization of the CCR rules.

See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Other Regulatory and Legislative Actions

Japan Earthquake and Tsunami and the Nuclear Industry's Response. On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co. Generation believes its nuclear generating facilities do not have the same operating risks as the Fukushima Daiichi plant because they meet the NRC's requirement that specifies all plants must be able to withstand the most severe natural phenomena historically reported for each plant's surrounding area, with a significant margin for uncertainty. In addition, Generation's plants are not located in significant earthquake zones or in regions where tsunamis are a threat. Generation believes its nuclear generating facilities are able to shut down safely and keep the fuel cooled through multiple redundant systems specifically designed to maintain electric power when electricity is lost from the grid. Further, Generation's nuclear generating facilities also undergo frequent scenario drills to ensure the proper function of the redundant safety protocols.

Since the events in Japan took place, Generation has continued to work with regulators and nuclear industry organizations to understand the events in Japan and apply lessons learned. Early on, the nuclear industry took a number of specific steps to respond, including actions requested by the Institute of Nuclear Power Operations (INPO) to perform tests that verified Generation's emergency equipment is available and functional, conduct walk-downs on its procedures related to critical safety equipment, confirm event response procedures and readiness to protect the spent fuel pool, and verify current qualifications of operators and support staff needed to implement the procedures. Generation has been addressing additional actions requested by INPO for improving and maintaining core and spent fuel pool cooling during an extended loss of power for at least 24 hours.

In April 2011, the NRC named six senior managers and staff to its task force for examining the agency's regulatory requirements, programs, processes, and implementation in light of information from the Fukushima Daiichi site in Japan, following the March 11 earthquake and tsunami (Task Force). On July 12, 2011, the NRC Task Force issued a report of its review of the accident, including recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The Task Force's report did not recommend any changes to the existing nuclear licensing process in the United States or changes in the storage of spent nuclear fuel within the plant's spent nuclear fuel pools. During the fourth quarter of 2011, the NRC staff issued its recommendations for prioritizing and implementing the Task Force recommendations and an implementation schedule which was approved by the NRC subject to a number of conditions. The NRC staff confirmed the Task Force's conclusions that none of the findings arising from the Task Force review presented an imminent risk to public health and safety.

In March 2012, the NRC authorized its staff to issue three immediately effective orders (Tier 1 orders) to commercial reactor licensees operating in the United States for compliance no later than December 31, 2016. In addition, in November 2012, the NRC staff recommended to the NRC the installation of engineered containment filtered venting systems for boiling-water reactors (BWR) with Mark I and Mark II containment structures. In summary, through the initial and/or subsequent orders and the NRC approved implementation guidance, the Tier I orders currently: (1) require licensees to provide sufficient onsite portable equipment and resources to maintain or restore cooling capabilities for the core and spent fuel pool and to maintain containment integrity until offsite equipment is available and have offsite equipment and resources available to sustain cooling functions indefinitely; (2) provide requirements for vents for BWR's with Mark I and Mark II containments to remain functional during severe accident conditions including the ability to vent the containment following core damage; and (3) require licensees to install instrumentation to provide a reliable indication of water level in the spent fuel pool. Finally, the NRC has directed the NRC staff to produce a technical evaluation to support rulemaking that considers filtering and performance-based strategies as options for BWR's with Mark I and Mark II containments. The NRC staff must then develop a final rule by March 2017.

Additionally, the NRC has issued a detailed information request to every operating commercial nuclear power plant in the United States. The information requested requires: (1) use of the current NRC guidance to reevaluate current seismic and flood risk hazards against the design basis and provide a plan of actions to address vulnerabilities, including risks exceeding the design basis; (2) performance of walk downs to ensure the ability to respond to seismic and external flooding events and provide a corrective action plan to the NRC to address deficiencies; and (3) assessment of the means to provide power for communications equipment during a severe natural event and identify staffing required to implement the emergency plan for an event affecting all units with an extended loss of alternating current power and impeded access to the site. The nuclear industry proposed an augmented approach to the seismic hazard analysis to accommodate industry wide availability of qualified technical resources needed to perform the required analysis. The NRC approved this augmented approach.

Generation has assessed the impacts of the Tier 1 orders and information requests and will continue monitoring the additional recommendations under review by the staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance for the period from 2013 through 2017 is expected to be approximately $350 million and $50 million of capital and operating expense, respectively, as previously anticipated in Generation's planning projections. As Generation completes the design and installation planning for its actions, Generation will update these estimates. Further, Generation believes that additional expenditures could be incurred during the period from 2018 to 2020 ranging from $25 million to $50 million in order to make the hardened vents at the eleven Mark I and II units capable of functioning under severe accident conditions and to complete seismic re-evaluations that have moved to this later time frame as a result of NRC acceptance of the augmented approach to seismic hazard analysis. Finally, Generation estimates incremental costs of $15 to $20 million per unit at eleven Mark I and II units for the installation of filtered vents, if ultimately required by the NRC. Generation's current assessments are specific to the Tier 1 recommendations as the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See Item 1A. Risk Factors of the Exelon 2012 Form 10-K, for further discussion of the risk factors.

Financial Reform Legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted in July 2010. While the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also provides for a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing, exchange trading, margin requirements, and other transparency requirements. The Dodd-Frank Act, however, also preserves the ability of end users in the energy industry to hedge their risks. In April 2012, the CFTC issued its rule defining swap dealers and major swap participants. Exelon has determined that it will conduct its commercial business in a manner that does not require registration as a swap dealer or major swap participant. Notwithstanding, there are additional rulemakings that have not yet been issued, including the capital and margin rules, which will further define the scope of the regulations and provide clarity as to the impact on the Registrants' business, as well as to potential new opportunities. Depending on these final rules, the Registrants could be subject to significant new obligations.

The proposed regulations addressing collateral and capital requirements and exchange margin cash postings, when final, could require Generation to increase collateral requirements or cash postings in lieu of letters of credit currently issued to collateralize Swaps. Exelon had previously estimated that it could be required to make up to $1 billion of additional collateral postings under its bilateral credit lines. Given the swap dealer and the major swap participant definitions will not apply to Generation, the actual amount of collateral postings that will be required may be lower than Exelon's previous expectations due to the following factors: (a) the majority of Generation's physical wholesale portfolio does not meet the final CFTC Swap definition; (b) there will be minimal incremental costs associated with Generation's positions that are currently cleared and subject to exchange margin; and (c) Generation will not be a swap dealer or major swap participant and proposed capital requirements applicable to these entities will not apply to Generation.

The actual level of collateral required will depend on many factors, including but not limited to market conditions, the outcome of final margin rules for Swaps, the extent of its trading activity in Swaps, and Generation's credit ratings. Nonetheless, Generation has adequate credit facilities and flexibility in its hedging program to meet its anticipated collateral requirements estimated based on conservative assumptions.

In addition, the new regulations will impose new and ongoing compliance and infrastructure costs on Generation, which may amount to several million dollars per year.

Exelon and Generation continue to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on their results of operations, cash flows or financial position.

ComEd, PECO and BGE could also be subject to various Dodd-Frank Act requirements to the extent they enter into Swap transactions. However, at this time, management of ComEd, PECO and BGE do not expect to be materially affected by this legislation.

Energy Infrastructure Modernization Act. Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. In addition, as long as ComEd is subject to EIMA, ComEd will fund customer assistance programs for low-income customers, which amounts will not be recoverable through rates.

ComEd files an annual reconciliation of the revenue requirement in effect in a given year to reflect the actual costs that the ICC determines are prudently and reasonably incurred for such year. Under the terms of EIMA, ComEd's target rate of return on common equity is subject to reduction if ComEd does not deliver the reliability and customer service benefits, as defined, it has committed to over the ten-year life of the investment program.

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: average vs. year-end rate base and capital structure, return on pension asset, and a weighted average cost of capital interest rate on the prior year reconciliation. 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. The ICC issued a rate order on June 5, 2013 approving ComEd's May 30, 2013 filing to update 2013 rates reflecting Senate Bill 9 impacts. In addition, the ICC issued an interim order approving ComEd's accelerated meter deployment plan. ComEd projects the override of Senate Bill 9 will result in increased operating revenues of approximately $15 million for the remainder of 2013 and $65 million in 2014, respectively. Also, ComEd projects that due to the Senate Bill 9 override it will accelerate capital expenditures by approximately $40 million and $45 million in 2013 and 2014, respectively.

See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

FERC Ameren Order. In July 2012, FERC issued an order indicating that Ameren Corporation (Ameren) had improperly included acquisition premiums/goodwill in its transmission formula rate, particularly in its capital structure and in the application of AFUDC. FERC also directed Ameren to make refunds for the implied increase in rates in prior years. Ameren has filed for rehearing regarding the July 2012 FERC order. ComEd believes that the FERC order authorizing its transmission formula rate is distinguishable from the circumstances that led to the July 2012 FERC order in the Ameren case. However, if ComEd were required to exclude acquisition premiums/goodwill from its transmission formula rate, the impact could be material to ComEd's results of operations and cash flows.

FERC Order No. 1000 Compliance. In FERC Order No. 1000, the FERC required public utility transmission providers to enhance their transmission planning procedures and their cost allocation methods applicable to certain new regional and interregional transmission projects. As part of the changes to the transmission planning procedures, the FERC required removal from all FERC-approved tariffs and agreements a federal right of first refusal to build certain new transmission facilities. In compliance with the regional transmission planning requirements of Order No. 1000, PJM as the transmission provider submitted a compliance filing to FERC on October 25, 2012. On the same day, certain of the PJM transmission owners including ComEd, PECO and BGE (collectively, the PJM Transmission Owners) submitted a filing asserting that their contractual rights embodied in the PJM governing documents continue to justify their right of first refusal to construct new reliability (and related) transmission projects and that the FERC should not be allowed to override such rights absent a showing that it is in the public interest to do so under the FERC's "*Mobile-Sierra*" standard of review. This is a heightened standard of review which the PJM Transmission Owners argued could not be satisfied based on the facts applicable to them. On March 22, 2013, FERC issued an order on the PJM Compliance Filing and the filing of these PJM Transmission Owners (1) rejecting the arguments of such PJM Transmission Owners that the PJM governing documents were entitled to review under the *Mobile-Sierra* standard, (2) accepting most of the PJM filing, removing the right-of-first refusal from the PJM tariffs; and (3) directing PJM to remove certain exceptions that it included in its compliance filing that FERC found did not comply with Order No. 1000. FERC's order could enable third parties to seek to build certain regional transmission projects that had previously been reserved for the PJM Transmission Owners, potentially reducing ComEd's, PECO's and BGE's financial return on new investments in energy transmission facilities. Numerous parties sought rehearing of the FERC's March 22, 2013 order, including the PJM Transmission Owners who sought rehearing of the FERC's rejection of their Mobile-Sierra and related arguments. The compliance filing was made on July 22, 2013.

FERC Transmission Complaint. On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the Pepco Holdings, Inc. companies relating to their respective transmission formula rates. As of June 30, 2013, BGE cannot predict the likelihood or a reasonable estimate of the amount of a change, if any, in the allowed base ROE, 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 ROE to 8.7%, the annual impact would be a reduction in revenues of approximately $10 million.

See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

2013 Maryland Electric and Gas Distribution Rate Case. 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. The new electric and gas distribution base rates are expected to take effect in December 2013. BGE cannot predict how much of the requested increases the MDPSC will approve.

See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Critical Accounting Policies and Estimates

Management of each of the Registrants makes a number of significant estimates, assumptions and judgments in the preparation of its financial statements. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies and Estimates" in the Exelon's, Generation's, ComEd's, PECO's and BGE's combined 2012 Form 10-K for a discussion of the estimates and judgments necessary in the Registrants' accounting for AROs, purchase accounting, asset impairments, depreciable lives of property, plant and equipment, defined benefit pension and other postretirement benefits, regulatory accounting, derivative instruments, taxation, contingencies and revenue recognition. At June 30, 2013, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2012.

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Results of Operations

Net Income (Loss) Attributable to Common Shareholders by Registrant

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012(a)	Favorable (Unfavorable) Variance
Exelon	$ 490	$ 286	$ 204	$ 486	$ 486	$ —
Generation	330	166	164	311	334	(23)
ComEd	96	42	54	14	129	(115)
PECO	72	79	(7)	193	175	18
BGE	22	13	9	100	(20)	120

(a) For BGE, reflects BGE's operations for the six months ended June 30, 2012. For Exelon and Generation, includes the operations of the acquired businesses from the date of the merger, March 12, 2012, through June 30, 2012.

Results of Operations — Generation

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012(a)	Favorable (Unfavorable) Variance
Operating revenues	$4,070	$3,765	$ 305	$7,603	$6,508	$ 1,095
Purchased power and fuel expense	1,946	1,852	(94)	4,114	2,896	(1,218)
Revenue net of purchased power and fuel(b)	2,124	1,913	211	3,489	3,612	(123)
Other operating expenses						
Operating and maintenance	1,189	1,178	(11)	2,302	2,356	54
Depreciation and amortization	210	204	(6)	424	357	(67)
Taxes other than income	101	90	(11)	194	164	(30)
Total other operating expenses	1,500	1,472	(28)	2,920	2,877	(43)
Equity in earnings (losses) of unconsolidated affiliates	(21)	(57)	36	(30)	(79)	49
Operating income	603	384	219	539	656	(117)
Other income and (deductions)						
Interest expense	(93)	(85)	(8)	(176)	(138)	(38)
Other, net	(33)	(76)	43	95	103	(8)
Total other income and (deductions)	(126)	(161)	35	(81)	(35)	(46)
Income before income taxes	477	223	254	458	621	(163)
Income taxes	149	58	(91)	148	289	141
Net income	328	165	163	310	332	(22)
Net loss attributable to noncontrolling interests	(2)	(1)	1	(1)	(2)	(1)
Net income on common stock	$ 330	$ 166	$ 164	$ 311	$ 334	$ (23)

(a) Includes the operations of the acquired businesses from the date of the merger, March 12, 2012, through June 30, 2012.

(b) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. Generation's net income increased compared to the same period in 2012 due to higher revenues, net of purchased power and fuel expense, higher earnings from Generation's interest in CENG and decreases in transaction costs and employee-related costs associated with the merger; partially offset by the impairment of certain generating assets in 2013, higher depreciation expense, higher property taxes, and unfavorable NDT fund performance. The increase in revenues, net of purchased power and fuel expense was primarily due to higher mark-to-market gains in 2013.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. Generation's net income decreased compared to the same period in 2012 due to lower revenue, net of purchased power and fuel, unfavorable NDT fund performance, higher depreciation expense, higher property taxes; partially offset by lower operating and maintenance expense and higher earnings from Generation's interest in CENG. The decrease in revenue, net of purchased power and fuel was primarily due to lower mark-to-market gains in 2013. The decrease in operating and maintenance was largely due to 2012 costs associated with a settlement with FERC in March 2012 and decreases in transaction costs and employee-related costs associated with the merger.

Revenue Net of Purchased Power and Fuel Expense

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

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the 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 New York ISO, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Regions not considered individually significant:
    - South represents operations in the FRCC and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
    - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
    - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: retail and wholesale gas, investments in natural gas exploration and production activities, proprietary trading, 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. Further, the following activities are not allocated to a region, and are reported in Other: compensation under the reliability-must-run rate schedule; results of operations from the Maryland Clean-Coal assets sold in the fourth quarter of 2012; unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities using the measure of revenue net of purchased power and fuel expense which is a non-GAAP measurement. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for internally generated energy and fuel costs associated with tolling agreements.

For the three and six months ended June 30, 2013 and 2012, Generation's revenue net of purchased power and fuel expense by region were as follows:

	Three Months Ended June 30,			
	2013	2012	Variance	% Change
Mid-Atlantic(b)	$ 768	$ 883	$ (115)	(13.0%)
Midwest(c)	684	764	(80)	(10.5%)
New England	50	60	(10)	(16.7%)
New York	14	39	(25)	(64.1%)
ERCOT	112	119	(7)	(5.9%)
Other Regions(d)	59	34	25	73.5%
Total electric revenue net of purchased power and fuel expense	$ 1,687	$ 1,899	$ (212)	(11.2%)
Proprietary Trading	3	15	(12)	(80.0%)
Mark-to-market gains	428	200	228	114.0%
Other(e)	6	(201)	207	(103.0%)
Total revenue net of purchased power and fuel expense	$ 2,124	$ 1,913	$ 211	11.0%

	Six Months Ended June 30,			
	2013	2012(a)	Variance	% Change
Mid-Atlantic(b)	$1,612	$1,653	$ (41)	(2.5%)
Midwest(c)	1,401	1,581	(180)	(11.4%)
New England	80	99	(19)	(19.2%)
New York	(8)	47	(55)	(117.0%)
ERCOT	213	153	60	39.2%
Other Regions(d)	105	48	57	118.8%
Total electric revenue net of purchased power and fuel expense	$3,403	$3,581	$ (178)	(5.0%)
Proprietary Trading	12	11	1	9.1%
Mark-to-market gains	25	260	(235)	(90.4%)
Other(e)	49	(240)	289	(120.4%)
Total revenue net of purchased power and fuel expense	$3,489	$3,612	$ (123)	(3.4%)

(a) Includes results for Constellation beginning on March 12, 2012, the date the merger was completed.
(b) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.

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(c) Results of transactions with ComEd are included in the Midwest region.
(d) Other Regions includes South, West and Canada, which are not considered individually significant.
(e) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date of $167 million and $341 million pre-tax for the three and six months ended June 30, 2013, and $414 million and $537 million pre-tax for the three and six months ended June 30, 2012.

Generation's supply sources by region are summarized below:

Supply source (GWh)	Three Months Ended June 30, 2013	2012	Variance	% Change
Nuclear generation(b)				
Mid-Atlantic	11,794	12,277	(483)	(3.9%)
Midwest	22,807	22,860	(53)	(0.2%)
Total Nuclear Generation	34,601	35,137	(536)	(1.5%)
Fossil and Renewables(b)				
Mid-Atlantic(b)(d)	2,796	2,316	480	20.7%
Midwest	318	228	90	39.5%
New England	3,132	2,755	377	13.7%
New York	—	—	—	—
ERCOT	1,617	2,177	(560)	(25.7%)
Other Regions(e)	1,431	1,923	(492)	(25.6%)
Total Fossil and Renewables	9,294	9,399	(105)	(1.1%)
Purchased power				
Mid-Atlantic(c)	2,616	7,111	(4,495)	(63.2%)
Midwest	1,503	1,558	(55)	(3.5%)
New England	1,365	3,905	(2,540)	(65.0%)
New York(c)	3,073	2,818	255	9.0%
ERCOT	4,269	6,686	(2,417)	(36.2%)
Other Regions(e)	4,998	6,012	(1,014)	(16.9%)
Total Purchased Power	17,824	28,090	(10,266)	(36.5%)
Total supply/sales by region(f)				
Mid-Atlantic(g)	17,206	21,704	(4,498)	(20.7%)
Midwest(h)	24,628	24,646	(18)	(0.1%)
New England	4,497	6,660	(2,163)	(32.5%)
New York	3,073	2,818	255	9.0%
ERCOT	5,886	8,863	(2,977)	(33.6%)
Other Regions(e)	6,429	7,935	(1,506)	(19.0%)
Total supply/sales by region	61,719	72,626	(10,907)	(15.0%)

Supply source (GWh)	Six Months Ended June 30, 2013	2012(a)	Variance	% Change
Nuclear generation(b)				
Mid-Atlantic	24,556	24,341	215	0.9%
Midwest	46,076	46,058	18	0.0%
Total Nuclear Generation	70,632	70,399	233	0.3%

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Supply source (GWh)	Six Months Ended June 30, 2013	2012(a)	Variance	% Change
Fossil and Renewables(b)				
Mid-Atlantic(b)(d)	5,956	4,107	1,849	45.0%
Midwest	899	500	399	79.8%
New England	5,524	3,644	1,880	51.6%
New York	—	—	—	—
ERCOT	2,350	3,017	(667)	(22.1%)
Other Regions(e)	3,685	2,742	943	34.4%
Total Fossil and Renewables	18,414	14,010	4,404	31.4%
Purchased power				
Mid-Atlantic(c)	5,849	9,688	(3,839)	(39.6%)
Midwest	3,203	4,110	(907)	(22.1%)
New England	2,872	5,005	(2,133)	(42.6%)
New York(c)	6,584	3,753	2,831	75.4%
ERCOT	8,468	9,518	(1,050)	(11.0%)
Other Regions(e)	8,701	7,781	920	11.8%
Total Purchased Power	35,677	39,855	(4,178)	(10.5%)
Total supply/sales by region(f)				
Mid-Atlantic(g)	36,361	38,136	(1,775)	(4.7%)
Midwest (h)	50,178	50,668	(490)	(1.0%)
New England	8,396	8,649	(253)	(2.9%)
New York	6,584	3,753	2,831	75.4%
ERCOT	10,818	12,535	(1,717)	(13.7%)
Other Regions(e)	12,386	10,523	1,863	17.7%
Total supply/sales by region	124,723	124,264	459	0.4%

(a) Includes results for Constellation beginning on March 12, 2012, the date the merger was completed.
(b) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly owned generating plants and does not include ownership through equity method investments (e.g., CENG).
(c) Purchased power for the three months and six months ended June 30, 2013 includes physical volumes of 3,114 GWh and 5,702 GWh in the Mid-Atlantic and 2,655 GWh and 5,868 GWh in New York as a result of the PPA with CENG. Purchased power for the three months and six months ended June 30, 2012 includes physical volumes of 3,225 GWh and 3,544 GWh in the Mid-Atlantic and 2,817 GWh and 3,539 GWh in New York as a result of the PPA with CENG.
(d) Excludes 2012 activity related to generation under the reliability-must-run rate schedule and generation of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger.
(e) Other Regions includes South, West and Canada, which are not considered individually significant.
(f) Excludes physical proprietary trading volumes of 1,995 GWh and 4,248 GWh for the three months ended June 30, 2013 and 2012, respectively, and 3,567 GWh and 6,077 GWh for the six months ended June 30, 2013 and 2012, respectively.
(g) Includes sales to PECO through the competitive procurement process of 1,242 GWh and 1,859 GWh for the three months ended June 30, 2013 and 2012, respectively, and 3,162 GWh and 3,488 GWh for the six months ended June 30, 2013 and 2012, respectively. Includes sales to BGE of 1,322 GWh and 1,076 GWh for the three months ended June 30, 2013 and 2012, respectively, and 2,857 GWh and 1,335 GWh for the six months ended June 30, 2013 and 2012, respectively.
(h) Includes sales to ComEd under the RFP procurement of 1,012 GWh and 865 GWh for the three months ended June 30, 2013 and 2012, respectively, and 1,012 GWh and 3,075 GWh for the six months ended June 30, 2013 and 2012, respectively.

The following table presents electric revenue net of purchased power and fuel expense per MWh of electricity sold during the three and six months ended June 30, 2013 as compared to the three and six months ended June 30, 2012.

$/MWh	Three Months Ended June 30, 2013	2012	% Change
Mid-Atlantic(b)	$ 44.64	$ 40.68	9.7%
Midwest(c)	27.77	31.00	(10.4%)
New England	11.12	9.01	23.4%
New York	4.56	13.84	(67.1%)
ERCOT	19.03	13.43	41.7%
Other Regions(d)	9.18	4.28	114.4%
Electric revenue net of purchased power and fuel expense per MWh (e)(f)	27.33	26.15	4.5%

$/MWh (a)	Six Months Ended June 30, 2013	2012(a)	% Change
Mid-Atlantic(b)	$44.33	$43.35	2.3%
Midwest(c)	27.92	31.20	(10.5%)
New England	9.53	11.45	(16.8%)
New York	(1.22)	12.52	(109.7%)
ERCOT	19.69	12.21	61.3%
Other Regions(d)	8.48	4.56	86.0%
Electric revenue net of purchased power and fuel expense per MWh(e)(f)	27.28	28.82	(5.3%)

(a) Includes financial results for Constellation beginning on March 12, 2012, the date the merger was completed.
(b) Includes sales to PECO of $97 million (1,242 GWh) and $125 million (1,859 GWh) for the three months ended June 30, 2013 and 2012 respectively. Includes sales to PECO of $238 million (3,162 GWh) and $236 million (3,488 GWh) for the six months ended June 30, 2013 and 2012 respectively. Includes sales to BGE of $99 million (1,322 GWh) and $84 million (1,076 GWh) for the three months ended June 30, 2013 and 2012, respectively. Includes sales to BGE of $212 million (2,857 GWh) and $102 million (1,335 GWh) for the six months ended June 30, 2013 and 2012, respectively. Excludes compensation under the reliability-must-run rate schedule and the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the merger.
(c) Includes sales to ComEd of $37 million (1,012 GWh) and $32 million (865 GWh) and settlements of the ComEd swap of $84 million and $171 million for the three months ended June 30, 2013 and 2012, respectively. Includes sales to ComEd of $37 million (1,012 GWh) and $115 million (3,075 GWh) and settlements of the ComEd swap of $229 million and $336 million for the six months ended June 30, 2013 and 2012, respectively
(d) Other Regions includes South, West and Canada, which are not considered individually significant.
(e) Revenue net of purchased power and fuel expense per MWh represents the average margin per MWh of electricity sold during the three and six months ended June 30, 2013 and 2012 and excludes the mark-to-market impact of Generation's economic hedging activities.
(f) Excludes Generation's other business activities not allocated to a region, including retail and wholesale gas, upstream natural gas, proprietary trading, energy efficiency, energy management and demand response. Also excludes Generation's compensation under the reliability-must-run rate schedule, the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in Q4 2012 as a result of the merger, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the Exelon and Constellation merger of $167 million and $414 million, for the three months ended June 30, 2013 and 2012, respectively, and $341 million and $537 million, for the six months ended June 30, 2013 and 2012, respectively.

Mid-Atlantic

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic of $115 million was primarily due to lower realized energy prices and increased nuclear fuel expense, partially offset by lower energy supply costs as a result of increased integration of Generation's energy generation and load businesses.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic of $41 million was primarily due to lower realized energy prices and increased nuclear fuel expense, partially offset by higher capacity revenues and the addition of Constellation in 2012.

Midwest

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The decrease in revenue net of purchased power and fuel expense in the Midwest of $80 million was primarily due to lower capacity revenues, lower realized energy prices, and increased nuclear fuel expense, partially offset by the early termination of certain contracts.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The decrease in revenue net of purchased power and fuel expense in the Midwest of $180 million was primarily due to lower capacity revenues, lower realized energy prices, and increased nuclear fuel expense, partially offset by the early termination of certain contracts and the addition of Constellation in 2012.

New England

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The $10 million decrease in revenue net of purchased power and fuel expense in New England was primarily due to decreased load served and increased fuel expense.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The $19 million decrease in revenue net of purchased power and fuel expense in New England was primarily due to decreased load served and increased fuel expense, partially offset by the addition of Constellation in 2012. Prior to the merger, New England was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

New York

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The $25 million decrease in revenue net of purchased power and fuel expense in New York was primarily the result of decreased realized energy prices.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The $55 million decrease in revenue net of purchased power and fuel expense in New York was primarily a result of decreased realized energy prices, partially offset by the addition of Constellation in 2012. Prior to the merger, New York was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

ERCOT

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The $7 million decrease in revenue net of purchased power and fuel expense in ERCOT was primarily as a result of decrease in load served, offset by increased realized energy prices.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The $60 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily as a result of the addition of Constellation in 2012.

Other Regions

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The $25 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of lower supply costs and increased integration of Generation's energy generation and load businesses.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The $57 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of lower supply costs, increased integration of Generation's energy generation and load businesses, and the addition of Constellation in 2012.

Mark-to-market

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on economic hedging activities were $428 million for the three months ended June 30, 2013 compared to gains of $200 million for the three months ended June 30, 2012. See Notes 9 — Fair Value of Financial Assets and Liabilities and 10 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. Mark-to-market gains on economic hedging activities were $25 million for the six months ended June 30, 2013 compared to gains of $260 million for the six months ended June 30, 2012. See Notes 9 — Fair Value of Financial Assets and Liabilities and 10 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Other

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The $207 million increase in other revenue net of purchased power and fuel was primarily due to the decrease in amortization of the acquired energy contracts recorded at fair value at the merger date. This increase was also due to the addition of Constellation in 2012, which includes wholesale and retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities in 2012. In addition, other revenue net of purchased power and fuel for 2012 includes the results of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in the fourth quarter 2012 as a result of the Exelon and Constellation merger. These positive factors were partially offset by a decrease in the compensation under the reliability-must-run rate schedule. See Note 4 – Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The $289 million increase in other revenue net of purchased power and fuel was primarily due to the addition of Constellation in 2012, in addition to the decrease of the amortization of the acquired energy contracts recorded at fair value at the merger date. In addition, other revenue net of purchased power and fuel for 2012 includes the results of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in the fourth quarter 2012 as a result of the Exelon and Constellation merger. These positive factors were partially offset by a decrease in the compensation under the reliability-must-run rate schedule. See Note 4 – Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Nuclear Fleet Capacity Factor and Production Costs

The following table presents nuclear fleet operating data for the three and six months ended June 30, 2013 as compared to the same periods in June 30, 2012, for the Generation-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Nuclear fleet production cost is defined as the costs to produce one MWh of energy, including fuel, materials, labor, contracting and other miscellaneous costs, but excludes depreciation and certain other non-production related overhead costs. Generation considers capacity factor and production costs useful measures comparatively to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Nuclear fleet capacity factor(a)	92.8 %	93.4 %	94.6 %	93.5 %
Nuclear fleet production cost per MWh(a)	$18.86	$18.48	$19.27	$19.27

(a) Reflects ownership percentage of stations operated by Exelon. Excludes Salem, which is operated by PSEG Nuclear, LLC, and Exelon's ownership in jointly owned generating plants through equity method investments (e.g. CENG).

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The nuclear fleet capacity factor decreased primarily due to more non-refueling outage days, partially offset by fewer refueling outage days, excluding Salem outages, during the three months ended June 30, 2013 compared to the same period in 2012. For the three months ended June 30, 2013 and 2012, non-refueling outage days totaled 31 and 16, respectively. During the same periods, refueling outage days totaled 47 and 51, respectively. Lower number of net MWhs generated and higher nuclear fuel costs resulted in a higher production cost per MWh for the three months ended June 30, 2013 as compared to the same period in 2012.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The nuclear fleet capacity factor increased primarily due to fewer refueling outage days, partially offset by more non-refueling outage days, excluding Salem outages, during the six months ended June 30, 2013 compared to the same period in 2012. For the six months ended June 30, 2013 and 2012, non-refueling outage days totaled 37 and 32, respectively. During the same periods, refueling outage days totaled 96 and 118, respectively.

Operating and Maintenance Expense

The changes in operating and maintenance expense for the three and six months ended June 30, 2013 compared to the same period in 2012, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
FERC settlement(a)	$ —	$ (195)
Labor, other benefits, contracting and materials	(5)	151
Impairment and related charges of certain generating assets	92	113
Constellation merger and integration costs	(19)	(71)
Maryland commitments	—	(35)
Corporate allocations(b)	(19)	13
Pension and non-pension postretirement benefits expense	—	7
Nuclear refueling outage costs, including the co-owned Salem plant(c)	29	3
Bodily injury costs(d)	(14)	(12)
Plant retirements and divestitures(e)	(43)	(56)
Bad debt expense	7	23
Other	(17)	5
Increase (decrease) in operating and maintenance expense	$ 11	$ (54)

(a) Reflects costs incurred as part of a March 2012 settlement with the FERC to resolve a dispute related to Constellation's prior period hedging and risk management transactions.

(b) The increase in cost allocations during six months ended June 30, 2013 reflects the impact of an increased share of corporate allocated costs due to the merger, partially offset during the three months ended June 30, 2013 primarily as a result of merger synergy savings for Exelon's corporate operations and shared service entities.
(c) Reflects primarily increased nuclear fueling outage costs related to Generation's ownership interest in Salem for three months ended June 30, 2013 compared to same period in 2012.
(d) Reflects decreased asbestos-related bodily injury expense.
(e) Reflects the operating and maintenance expense associated with the generating assets retired or divested during 2012.

Depreciation and Amortization

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The increase in depreciation and amortization was primarily due to higher plant balances resulting from capital additions, increased nuclear fuel amortization costs, and the completion of wind and solar facilities placed into service in the second half of 2012 and in the first half of 2013.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The increase in depreciation and amortization was primarily due to higher plant balances resulting from the addition of Constellation's plant balances for full year to date 2013. The increase in depreciation and amortization expense was also due capital additions, increased nuclear fuel amortization costs, and the completion of wind and solar facilities placed into service in the second half of 2012 and in the first half of 2013.

Taxes Other Than Income

The increase in taxes other than income for the three and six months ended June 30, 2013 as compared to the three and six months ended June 30, 2012 was primarily due to higher property taxes. The increase in taxes other than income for the six months ended June 30, 2013 compared to six months ended June 30, 2012 was also due to addition of Constellation's financial results in 2012.

Equity in Loss of Unconsolidated Affiliates

The decrease in Equity in loss of unconsolidated affiliates for the three and six months ended June 30, 2013 was primarily due to higher net income generated from Generation's equity investment in CENG in 2013 compared to same period in 2012 and lower amortization of the basis difference of Generation's ownership interest in CENG recorded at fair value in connection with the Merger.

Interest Expense

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The increase in interest expense was primarily due to the reversal of previously capitalized interest expense related to power uprate projects that were cancelled during second quarter of 2013.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The increase in interest expense was primarily due to the increase in long-term debt as a result of the merger and the reversal of previously capitalized interest expense related to power uprate projects that were cancelled during second quarter of 2013.

Other, Net

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. Other, net primarily reflects the change in the net unrealized gains (losses) related to the NDT funds of the Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $43 million of credit facility termination fees recorded in 2012.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. Other, net primarily reflects the change in the net unrealized gains (losses) related to the NDT funds of the Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $30 million and $52 million of income in 2013 and 2012, respectively, related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units and $42 million of credit facility termination fees recorded in 2012

The following table provides unrealized and realized gains and losses on the NDT funds of the Non-Regulatory Agreement Units recognized in other, net for the three and six months ended June 30, 2013 and 2012:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net unrealized gains (losses) on decommissioning trust funds	$ (40)	$ (35)	$ 24	$ 30
Net realized gains on sale of decommissioning trust funds	$ —	$ 3	$ 2	$ 40

Effective Income Tax Rate

The effective income tax rate was 31.2% and 32.3% for the three and three months ended June 30, 2013, respectively, compared to 26.0% and 46.5% for the same periods during 2012. See Note 12 of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in the effective income tax rate.

Results of Operations — ComEd

	Three Months Ended June 30,		Favorable (Unfavorable) Variance	Six Months Ended June 30,		Favorable (Unfavorable) Variance
	2013	2012		2013	2012	
Operating revenues	$ 1,080	$ 1,281	$ (201)	$2,239	$2,670	$ (431)
Purchased power expense	248	587	339	630	1,208	578
Revenue net of purchased power expense(a)	832	694	138	1,609	1,462	147
Other operating expenses						
Operating and maintenance	359	331	(28)	687	650	(37)
Depreciation and amortization	170	152	(18)	337	300	(37)
Taxes other than income	71	69	(2)	145	144	(1)
Total other operating expenses	600	552	(48)	1,169	1,094	(75)
Operating income	232	142	90	440	368	72
Other income and (deductions)						
Interest expense, net	(76)	(74)	(2)	(429)	(156)	(273)
Other, net	6	3	3	11	7	4
Total other income and (deductions)	(70)	(71)	1	(418)	(149)	(269)
Income before income taxes	162	71	91	22	219	(197)
Income taxes	66	29	(37)	8	90	82
Net income	$ 96	$ 42	$ 54	$ 14	$ 129	$ (115)

(a) ComEd evaluates its operating performance using the measure of revenue net of purchased power expense. ComEd believes that revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income

Three Months Ended June 30, 2013, Compared to Three Months Ended June 30, 2012. ComEd's net income for the three months ended June 30, 2013, was higher than the same period in 2012, primarily due to the discrete impacts of the ICC's May 2012 Order in ComEd's 2011 formula rate proceeding under EIMA and the enactment of Senate Bill 9 in May 2013. The increase to net income was partially offset by unfavorable weather conditions in 2013 compared to the same period in 2012. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Six Months Ended June 30, 2013, Compared to Six Months Ended June 30, 2012. ComEd's net income for the six months ended June 30, 2013, was lower than the same period in 2012, primarily due to the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013 and unfavorable weather conditions in the second quarter of 2013 compared to the same period in 2012. The decrease to net income was partially offset by the discrete impacts of the ICC's May 2012 Order in ComEd's 2011 formula rate proceeding under EIMA and the enactment of Senate Bill 9 in May 2013. See Notes 5 — Regulatory Matters and 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Operating Revenues Net of Purchased Power Expense

There are certain drivers of revenue that are fully offset by their impact on purchased power expense, such as commodity procurement costs and customer choice programs. ComEd is permitted to recover electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on revenue net of purchased power expense. See Note 5 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process.

Electric revenues and purchased power expense are affected by fluctuations in customers' purchases from competitive retail electric suppliers. All ComEd customers have the choice to purchase electricity from an alternative retail electric supplier. The customers' choice of retail electric supplier does not impact ComEd's volume of deliveries, but does affect ComEd's energy revenue. The number of retail customers purchasing electricity from alternative retail electric suppliers was 2,593,064 and 668,209 at June 30, 2013, and 2012, respectively, representing 68% and 17% of total retail customers, respectively. Retail energy purchased from alternative electric suppliers represented 81% and 78% of ComEd's retail kWh sales for the three months and six months ended June 30, 2013, respectively, as compared to 62% and 61% for the three and six months ended June 30, 2012, respectively. During 2012, the City of Chicago and approximately 240 Illinois municipalities (which by reference also includes governmental entities such as townships and counties) approved referenda regarding electric supply aggregation. This approval allowed governmental officials to identify and sign contracts with alternative retail electric suppliers on behalf of the eligible retail customers in its community. Additionally, the referenda provided customers with the ability to opt-out of the municipal aggregation program. As of June 30, 2013, there are approximately 330 municipalities that have approved a municipal aggregation referendum in the ComEd service territory. As a result, approximately two-thirds of residential usage as of June 30, 2013 is being supplied by alternative retail electric suppliers and it is estimated that over 80% of that usage resulted from municipal aggregation activities. It is anticipated that as municipalities implement their aggregation programs throughout 2013, and as non-municipality aggregation switching continues to grow, that approximately three-quarters of total residential usage will be supplied by retail electric suppliers by the end of 2013.

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The changes in ComEd’s revenue net of purchased power expense for the three months and six months ended June 30, 2013, compared to the same periods in 2012 consisted of the following:

	Three Months Ended June 30, 2013 Increase (Decrease)	Six Months Ended June 30, 2013 Increase (Decrease)
Weather	$ (22)	$ (4)
Volume	5	1
Electric distribution revenues	53	77
Discrete impacts of the 2012 Distribution Rate Case Order	100	88
Senate Bill 9	10	10
Transmission revenues	3	3
Regulatory required programs	(2)	1
Uncollectible accounts recovery, net	(3)	(17)
Other	(6)	(12)
Total increase	$ 138	$ 147

Weather. The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as “favorable weather conditions” because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand. Through June, ComEd’s service territory experienced mild weather in 2013, compared to the warmest January through June period on record in 2012. For the three and six months ended June 30, 2013, the increase in revenue net of purchased power expense was offset by unfavorable weather conditions as a result of the mild weather in the second quarter of 2013, compared to the same period in 2012.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd's service territory with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd’s service territory for the three months and six months ended June 30, 2013 and 2012, consisted of the following:

				% Change	
Heating and Cooling Degree-Days	2013	2012	Normal	From 2012	From Normal
Three Months Ended June 30,					
Heating Degree-Days	778	544	765	43.0 %	1.7 %
Cooling Degree-Days	240	423	218	(43.3)%	10.1 %
Six Months Ended June 30,					
Heating Degree-Days	4,037	2,928	3,929	37.9 %	2.7 %
Cooling Degree-Days	240	462	218	(48.1)%	10.1 %

Volume. Revenue net of purchased power expense increased as a result of higher delivery volume, exclusive of the effects of weather, for the three months ended June 30, 2013, reflecting increased average usage per residential customer as compared to the same period in 2012.

Electric Distribution Revenues. EIMA provides for a performance-based formula rate tariff, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. During the three and six months ended June 30, 2013, ComEd recorded increased revenue net of purchased power expense of $53 million and $77 million, respectively, associated with the 2011 through 2013 reconciliations. These amounts exclude the discrete impacts of the May 2012 Distribution Rate Case Order and the enactment of Senate Bill 9, as discussed below. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Discrete Impacts of the 2012 Distribution Rate Case Order. On May 30, 2012, the ICC issued its final Order related to ComEd's 2011 formula rate proceeding under EIMA, which resulted in a reduction to revenue net of purchased power expense of $100 million and $88 million, for the three and six months ended June 30, 2012. See Note 3 — Regulatory Matters of the Exelon 2012 Form 10-K for further information.

Senate Bill 9. On May 22, 2013, the Illinois General Assembly overrode the Governor's May 5, 2013 veto of Senate Bill 9, which became effective immediately. Revenue net of purchased power expense increased by $10 million for the three and six months ended June 30, 2013, as a result of the enactment of Senate Bill 9. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenues. ComEd's transmission rates are established based on a FERC-approved formula. ComEd's most recent annual formula rate update, filed in April 2013, reflects 2012 actual costs plus forecasted 2013 capital additions. Transmission revenue net of purchased power expense vary from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants, such as the highest daily peak load from the previous calendar year. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. Revenues related to regulatory required programs are the recoveries from customers for costs of various legislative and/or regulatory programs on a full and current basis through approved regulated rates. Programs include ComEd's energy efficiency and demand response and purchased power administrative costs. An equal and offsetting amount has been reflected in operating and maintenance expense during the periods presented. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net. Represents recoveries under ComEd's uncollectible accounts tariff. Refer to the operating and maintenance expense discussion below for additional information on this tariff.

Other. Other revenues decreased during the three and six months ended June 30, 2013, compared to the same periods in 2012. Other revenues, which can vary period to period, include rental revenues, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs, and recoveries of environmental costs associated with MGP sites.

Operating and Maintenance Expense

	Three Months Ended June 30,		Increase	Six Months Ended June 30,		Increase
	2013	2012	(Decrease)	2013	2012	(Decrease)
Operating and maintenance expense — baseline	$ 304	$ 274	$ 30	$ 593	$ 557	$ 36
Operating and maintenance expense — regulatory required programs(a)	55	57	(2)	94	93	1
Total operating and maintenance expense	$ 359	$ 331	$ 28	$ 687	$ 650	$ 37

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for the three and six months ended June 30, 2013 compared to the same periods in 2012, consisted of the following:

	Three Months Ended June 30 Increase (Decrease)	Six Months Ended June 30 Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials(a)	$ 10	$ 26
Pension and non-pension postretirement benefits expense	4	10
Storm-related costs(b)	11	9
Uncollectible accounts expense — provision(c)	(2)	(9)
Uncollectible accounts expense — recovery, net(c)	(1)	(8)
Other	8	8
	30	36
Regulatory required programs		
Energy efficiency and demand response programs	(2)	1
Purchased power administrative costs	—	—
	(2)	1
Increase in operating and maintenance expense	$ 28	$ 37

(a) The increase includes contracting costs resulting from new projects associated with EIMA. See Note 5 — Regulatory Matters of the Combined Notes to Financial Statements for additional information regarding EIMA.
(b) Under EIMA, ComEd may recover costs associated with certain one-time events, such as large storms, over a five-year period. During the second quarter of 2013, ComEd recorded a net reduction in operating and maintenance expense for costs related to one significant second quarter 2013 storm.
(c) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism.

Depreciation and Amortization

Depreciation and amortization expense increased during the three and six months ended June 30, 2013 compared to the same periods in 2012, primarily due to ongoing capital expenditures and increased regulatory asset amortization related to higher MGP remediation expenditures.

Taxes Other Than Income

Taxes other than income taxes increased for the three and six months ended June 30, 2013, compared to the same period in 2012, primarily due to increased Illinois electricity distribution taxes. Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes, and payroll taxes.

Interest Expense, Net

The changes in Interest Expense, net for the three and six months ended June 30, 2013, compared to the same period in 2012, consisted of the following:

	Three Months Ended June 30, 2013 Increase (Decrease)	Six Months Ended June 30, 2013 Increase (Decrease)
Interest expense related to uncertain tax positions(a)	$ —	$ 277
Interest expense on debt (including financing trusts)	2	(1)
Other	—	(3)
Increase in interest expense, net	$ 2	$ 273

(a) Primarily reflects the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013. See Note 12 of the Combined Notes to Financial Statements for additional information.

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Effective Income Tax Rate

The effective income tax rate was 40.7% for the three months ended June 30, 2013 compared to 40.8% for the same period during 2012. The effective income tax rate was 36.4% for the six months ended June 30, 2013 compared to 41.1% for the same period during 2012. See Note 12 of the Combined Notes to Consolidated Financial Statements for further discussion of the change in the effective income tax rate.

ComEd Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)				
Residential	6,090	6,674	(8.8)%	1.1%
Small commercial & industrial	7,832	7,888	(0.7)%	2.2%
Large commercial & industrial	6,711	6,839	(1.9)%	(0.6)%
Public authorities & electric railroads	294	293	0.3%	4.0%
Total Retail Deliveries	20,927	21,694	(3.5)%	1.0%

Retail Deliveries to Customers (in GWhs)	Six Months Ended June 30, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)				
Residential	12,966	13,080	(0.9)%	0.5%
Small commercial & industrial	15,705	15,804	(0.6)%	(0.6)%
Large commercial & industrial	13,551	13,542	0.1%	(0.5)%
Public authorities & electric railroads	667	617	8.1%	11.6%
Total Retail Deliveries	42,889	43,043	(0.4)%	(0.2)%

Number of Electric Customers	As of June 30, 2013	2012
Residential	3,465,712	3,456,312
Small commercial & industrial	366,153	365,474
Large commercial & industrial	2,006	1,990
Public authorities & electric railroads	4,852	4,793
Total	3,838,723	3,828,569

Electric Revenue	Three Months Ended June 30, 2013	2012	% Change	Six Months Ended June 30, 2013	2012	% Change
Retail Delivery and Sales(a)						
Residential	$ 476	$ 720	(33.9)%	$1,060	$1,496	(29.1)%
Small commercial & industrial	315	306	2.9%	623	654	(4.7)%
Large commercial & industrial	113	94	20.2%	215	194	10.8%
Public authorities & electric railroads	12	9	33.3%	24	21	14.3%
Total Retail	916	1,129	(18.9)%	1,922	2,365	(18.7)%
Other Revenue(b)	164	152	7.9%	317	305	3.9%
Total Electric Revenues	$ 1,080	$ 1,281	(15.7)%	$2,239	$2,670	(16.1)%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.

(b) Other revenue primarily includes transmission revenue from PJM. Other items include rental revenues, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs, and recoveries of environmental costs associated with MGP sites.

Results of Operations — PECO

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	Favorable (Unfavorable) Variance
Operating revenues	$ 672	$ 715	$ (43)	$1,567	$1,590	$ (23)
Purchased power and fuel	258	296	38	664	707	43
Revenue net of purchased power and fuel(a)	414	419	(5)	903	883	20
Other operating expenses						
Operating and maintenance	181	172	(9)	369	375	6
Depreciation and amortization	56	54	(2)	113	107	(6)
Taxes other than income	39	42	3	80	74	(6)
Total other operating expenses	276	268	(8)	562	556	(6)
Operating income	138	151	(13)	341	327	14
Other income and (deductions)						
Interest expense, net	(28)	(31)	3	(57)	(62)	5
Other, net	—	2	(2)	3	5	(2)
Total other income and (deductions)	(28)	(29)	1	(54)	(57)	3
Income before income taxes	110	122	(12)	287	270	17
Income taxes	32	42	10	87	93	6
Net income	78	80	(2)	200	177	23
Preferred security dividends and redemption	6	1	5	7	2	5
Net income attributable to common shareholders	$ 72	$ 79	$ (7)	$ 193	$ 175	$ 18

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income attributable to common shareholders

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The decrease in net income attributable to common shareholders was driven primarily by lower operating revenue net of purchased power and fuel expense and an increase in operating and maintenance expenses, partially offset by lower income tax expense.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The increase in net income attributable to common shareholders was driven primarily by higher operating revenue net of purchased power and fuel expense and decreases in operating and maintenance expenses and interest expense, partially offset by increases in depreciation and amortization expense and taxes other than income. The increase in revenue net of purchased power and fuel was the result of weather, which was partially offset by the impact of pricing.

Operating Revenues, Purchased Power and Fuel Expense

There are certain drivers to operating revenues that are offset by their impact on purchased power expense and fuel expense, such as commodity procurement costs and customer choice programs. Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs.

PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments at least quarterly that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with the PAPUC's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and gas revenue net of purchased power and fuel expense.

Electric and gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customer's choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and gas revenue net of purchased power and fuel expense. The number of retail customers purchasing electricity from a competitive electric generation supplier was 523,900 and 441,000 at June 30, 2013 and 2012, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 70% and 68% of PECO's retail kWh sales for the three and six months ended June 30, 2013, respectively, compared to 67% and 65% for the three and six months ended June 30, 2012. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 59,100 and 42,100 at June 30, 2013 and 2012, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 21% and 18% of PECO's mmcf sales for the three and six months ended June 30, 2013, respectively, compared to 18% and 14% for the three and six months ended June 30, 2012.

The changes in PECO’s operating revenues net of purchased power and fuel expense for the three months ended June 30, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ (2)	$ 2	$—
Volume	(3)	—	(3)
Pricing	—	(2)	(2)
Regulatory required programs	6	—	6
Other	(6)	—	(6)
Total decrease	$ (5)	$—	$ (5)

The changes in PECO’s operating revenues net of purchased power and fuel expense for the six months ended June 30, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ 16	$27	$ 43
Volume	(3)	(2)	(5)
Pricing	(9)	(5)	(14)
Regulatory required programs	4	—	4
Other	(9)	1	(8)
Total (decrease) increase	$ (1)	$21	$ 20

Weather

The demand for electricity and gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as “favorable weather conditions” because these weather conditions result in increased deliveries of electricity and gas. Conversely, mild weather reduces demand. During the three months ended June 30, 2013 compared to the same period in 2012, electric and gas revenues net of purchased power remained relatively level compared to the same period in 2012.

During the six months ended June 30, 2013 compared to the same period in 2012, operating revenues net of purchased power and fuel expense were higher due to the impact of favorable 2013 winter weather conditions in PECO's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the three and six months ended June 30, 2013 compared to the same periods in 2012 and normal weather consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2013**	**2012**	**Normal**	**From 2012**	**From Normal**
Three Months Ended June 30,					
Heating Degree-Days	421	337	463	24.9 %	(9.1)%
Cooling Degree-Days	418	430	348	(2.8)%	20.1 %
Six Months Ended June 30,					
Heating Degree-Days	2,861	2,251	2,939	27.1%	(2.7)%
Cooling Degree-Days	418	434	348	(3.7)%	20.1%

Volume

The decrease in electric operating revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, for the three and six months ended June 30, 2013 compared to the same periods in 2012 reflected the impact of energy efficiency initiatives on customer usages offset by the oil refineries returning to full production in 2013.

Pricing

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The decrease in gas revenues net of fuel expense as a result of pricing reflects the refund of the tax cash benefit resulting from the change in PECO's method of accounting for gas distribution repairs in 2012. The refund was reflected on customer bills as a credit beginning January 1, 2013. The accounting impact of the refund is completely offset by regulatory liability amortization recorded in income tax expense.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The decrease in electric operating revenues net of purchased power expense as a result of pricing reflects lower overall effective rates due to increased usage per customer across all customer classes. The decrease in gas revenue net of fuel expense as a result of pricing for the six months ended June 30, 2013, is driven by the refund of the tax cash benefit resulting from the change in PECO's method of accounting for gas distribution repairs in 2012. The refund was reflected on customer bills as a credit beginning January 1, 2013. The accounting impact of the refund is completely offset by regulatory liability amortization recorded in income tax expense.

Regulatory Required Programs

This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The offsetting costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Other

The decrease in other electric revenues net of purchased power expense for the three and six months ended June 30, 2013 compared to the same periods in 2012 reflected a decrease in GRT revenue as a result of lower supplied energy service and wholesale transmission revenue earned by PECO due to increased participation in the customer choice program. There is an equal and offsetting decrease in GRT expense included in taxes other than income.

Operating and Maintenance Expense

	Three Months Ended June 30,		Increase (Decrease)	Six Months Ended June 30,		Increase (Decrease)
	2013	2012		2013	2012	
Operating and Maintenance Expense — Baseline	$ 155	$ 151	$ 4	$ 329	$ 335	$ (6)
Operating and Maintenance Expense — Regulatory Required Programs(a)	26	21	5	40	40	—
Total Operating and Maintenance Expense	181	172	9	369	375	(6)

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for the three and six months ended June 30, 2013 compared to the same periods in 2012, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ 13	$ 9
Storm-related costs	(1)	—
Pension and non-pension postretirement benefits expense	(3)	(6)
Constellation merger and integration costs	(2)	(5)
Other	(3)	(4)
	4	(6)
Regulatory Required Programs		
Smart Meter	1	—
Energy Efficiency	4	—
	5	—
Increase (Decrease) in operating and maintenance expense	$ 9	$ (6)

Depreciation and Amortization Expense

The increase in depreciation and amortization expense for the three and six months ended June 30, 2013 compared to the same periods in 2012 was primarily due to ongoing capital expenditures as well as increased depreciation and amortization expense related to the smart meter AMI infrastructure. An equal and offsetting amount for the depreciation and amortization expense related to the smart meter AMI infrastructure has been reflected in operating revenues during the periods represented.

Taxes Other Than Income

The decrease in taxes other than income for the three months ended June 30, 2013 compared to the same period in 2012 was primarily due to decreased GRT collections as a result of lower revenues. An equal and offsetting decrease in GRT has been reflected in operating revenues during the current period.

The increase in taxes other than income for the six months ended June 30, 2013 compared to the same period in 2012 is primarily due to a favorable sales and use tax reserve adjustment resulting from the completion of the audit of tax years 2005 through 2010 recorded in the first quarter of 2012. This increase was offset slightly by decreased GRT collections as a result of lower revenues. An equal and offsetting decrease in GRT has been reflected in operating revenues during the current period.

Interest Expense, Net

The decrease in interest expense, net for the three and six months ended June 30, 2013 compared to the same periods in 2012 was primarily due to lower interest expense as a result of refinancing debt retired at lower interest rates during the second half of 2012.

Other, Net

The change in Other, net for the three and six months ended June 30, 2013 remained relatively level compared to the same period in 2012.

Effective Income Tax Rate

PECO's effective income tax rate was 29.1% and 34.4% for the three months ended June 30, 2013 and 2012, respectively, and 30.3% and 34.4% for the six months ended June 30, 2013 and 2012, respectively. The effective income tax rate for the three and six months ended June 30, 2013 reflects the impact of the tax benefit recognized in 2013 related to the gas repairs deduction and the gas repairs bill credit amortization which was not included in the second quarter of 2012. See Note 12 — Income Taxes of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in effective income tax rate.

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PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2013	2012	% Change	Weather-Normal % Change	Six Months Ended June 30, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)								
Residential	2,888	2,929	(1.4)%	(0.8)%	6,353	6,095	4.2%	(0.1)%
Small commercial & industrial	1,960	1,959	0.1%	0.9%	3,969	3,910	1.5%	(1.9)%
Large commercial & industrial	3,784	3,743	1.1%	1.9%	7,430	7,380	0.7%	1.7%
Public authorities & electric railroads	238	237	0.4%	0.4%	493	474	4.0%	4.0%
Total Electric Retail Deliveries	8,870	8,868	0.0%	0.8%	18,245	17,859	2.2%	0.4%

Number of Electric Customers	As of June 30, 2013	2012
Residential	1,419,977	1,417,346
Small commercial & industrial	148,723	148,837
Large commercial & industrial	3,109	3,107
Public authorities & electric railroads	9,672	9,680
Total	1,581,481	1,578,970

Electric Revenue	Three Months Ended June 30, 2013	2012	% Change	Six Months Ended June 30, 2013	2012	% Change
Retail Delivery and Sales(a)						
Residential	$ 354	$ 393	(9.9)%	$ 749	$ 800	(6.4)%
Small commercial & industrial	109	119	(8.4)%	215	237	(9.3)%
Large commercial & industrial	61	59	3.4%	120	113	6.2%
Public authorities & electric railroads	8	8	0.0%	16	16	0.0%
Total Retail	532	579	(8.1)%	1,100	1,166	(5.7)%
Other Revenue(b)	53	56	(5.4)%	108	112	(3.6)%
Total Electric Revenues	$ 585	$ 635	(7.9)%	$ 1,208	$ 1,278	(5.5)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.

(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.

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PECO Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended June 30, 2013	2012	% Change	Weather-Normal % Change	Six Months Ended June 30, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales								
Retail sales(a)	6,919	6,228	11.1%	0.6%	35,357	28,655	23.4%	(0.2)%
Transportation and other	5,956	5,835	2.1%	3.5%	14,839	13,601	9.1%	2.3%
Total Gas Deliveries	12,875	12,063	6.7%	1.8%	50,196	42,256	18.8%	0.5%

Number of Gas Customers	As of June 30, 2013	2012
Residential	455,518	452,478
Commercial & industrial	41,648	41,383
Total Retail	497,166	493,861
Transportation	903	888
Total	498,069	494,749

Gas Revenue	Three Months Ended June 30, 2013	2012	% Change	Six Months Ended June 30, 2013	2012	% Change
Retail Delivery and Sales						
Retail sales(a)	$ 78	$ 73	6.8%	$ 338	$ 295	14.6%
Transportation and other	9	7	28.6%	21	17	23.5%
Total Gas Revenues	$ 87	$ 80	8.8%	$ 359	$ 312	15.1%

(a) Reflects delivery volumes and revenues from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.

Results of Operations — BGE

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	Favorable (Unfavorable) Variance
Operating revenues	$ 653	$ 616	$ 37	$1,533	$1,312	$ 221
Purchased power and fuel	288	285	(3)	713	670	(43)
Revenue net of purchased power and fuel(a)	365	331	34	820	642	178
Other operating expenses						
Operating and maintenance	160	161	1	303	356	53
Depreciation and amortization	82	71	(11)	175	150	(25)
Taxes other than income	54	47	(7)	109	95	(14)
Total other operating expenses	296	279	(17)	587	601	14
Operating income	69	52	17	233	41	192
Other income and (deductions)						
Interest expense, net	(32)	(34)	2	(66)	(75)	9
Other, net	4	7	(3)	9	13	(4)
Total other income and (deductions)	(28)	(27)	(1)	(57)	(62)	5
Income (loss) before income taxes	41	25	16	176	(21)	197
Income taxes	16	9	(7)	70	(7)	(77)
Net income (loss)	25	16	9	106	(14)	120
Preference stock dividends	3	3	—	6	6	—
Net income (loss) attributable to common shareholder	$ 22	$ 13	$ 9	$ 100	$ (20)	$ 120

(a) BGE evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenue net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net income (loss) attributable to common shareholders

Three Months Ended June 30, 2013, Compared to Three Months Ended 2012. BGE's net income attributable to common shareholders for the three months ended June 30, 2013, was higher than the same period in 2012, primarily due to higher electric and gas distribution rates, effective February 23, 2013, pursuant to the MDPSC order in BGE's 2012 rate case.

Six Months Ended June 30, 2013, Compared to Six Months Ended 2012. BGE's net income attributable to common shareholders for the six months ended June 30, 2013, was higher than the same period in 2012, primarily due to decreased operating revenue net of purchased power and fuel expense in 2012 related to the accrual of the residential customer rate credit and the accrual of its portion of the charitable contributions which were conditions of the MDPSC's approval of Exelon's merger with Constellation. The increase in net income attributable to common shareholders was also driven by higher electric and gas distribution rates pursuant to the MDPSC order in BGE's 2012 rate case.

Operating Revenues, Purchased Power and Fuel Expense

There are certain drivers to operating revenue that are offset by their impact on purchased power expense and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively.

The number of customers electing to select a competitive electric generation supplier affects electric SOS revenues and purchased power expense. The number of customers electing to select a competitive natural gas supplier affects gas cost adjustment revenues and purchased natural gas expense. All BGE customers have the choice to purchase energy from a competitive electric generation supplier. This customer choice of electric generation suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to SOS. The number of retail customers purchasing electricity from a competitive electric generation supplier was 389,400 and 338,400 at June 30, 2013 and 2012, respectively, representing 31% and 27% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 63% and 61% of BGE's retail kWh sales for the three and six months ended June 30, 2013, respectively compared to 62% and 61% for the three and six months ended June 30, 2012, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 161,900 and 125,300 at June 30, 2013 and 2012, respectively, representing 25% and 19% of total retail customers, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 63% and 51% of BGE's retail mmcf sales for the three and six months ended June 30, 2013, respectively, compared to 67% and 55% for the three and six months ended June 30, 2012, respectively.

The changes in BGE's operating revenues net of purchased power and fuel expense for the three months ended June 30, 2013 compared to the same period in 2012, consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Pricing	$ 18	$ 5	$ 23
Regulatory required programs	8	1	9
Other	1	1	2
Total increase	$ 27	$ 7	$ 34

The changes in BGE's operating revenues net of purchased power and fuel expense for the six months ended June 30, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Residential customer rate credit(a)	$ 82	$31	$113
Pricing	24	8	32
Regulatory required programs	19	5	24
Other	7	2	9
Total increase	$ 132	$46	$178

(a) In accordance with the MDPSC order approving Exelon's merger with Constellation, the residential customer rate credit is not recoverable from BGE's customers. 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.

Revenue Decoupling. The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenues from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Volume. Heating degree days are quantitative indices that reflect the demand for energy needed to heat a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE's service territory. The changes in heating degree days in BGE's service territory for the three and six months ended June 30, 2013 compared to the same period in 2012 consisted of the following:

Heating and Cooling Degree-Days	2013	2012	Normal	% Change From 2012	% Change From Normal
Three Months Ended June 30,					
Heating Degree-Days	492	402	517	22.4 %	(4.8)%
Cooling Degree-Days	263	289	250	(9.0)%	5.2%
Six Months Ended June 30,					
Heating Degree-Days	2,943	2,275	2,902	29.4%	1.4%
Cooling Degree-Days	264	299	250	(11.7)%	5.6%

Residential Customer Rate Credit. The residential customer rate credit provided in 2012 as a result of the MDPSC's order approving Exelon's merger with Constellation decreased operating revenues net of purchased power and fuel for the six months ended June 30, 2013 compared to the same period in 2012.

Pricing. The increase in operating revenues net of purchased power and fuel expense as a result of pricing for the three and six months ended June 30, 2013 compared to the same period in 2012 primarily reflected the impact of the new electric and natural gas distribution rates charged to customers that became effective February 23, 2013 in accordance with the 2012 MDPSC approved electric and natural gas distribution rate case order. See Note 5 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for further information.

Regulatory Required Programs. This represents the change in revenues collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. The increase in revenues during the three and six months ended June 30, 2013 compared to the same period in 2012 was primarily due to the recovery of higher energy efficiency program costs.

Other. Other revenues increased during the three and six months ended June 30, 2013 compared to the same period in 2012. Other revenues, which can vary from period to period, include miscellaneous revenues such as late payment charge revenues and all base distribution revenues, which increased due to customer mix.

Operating and Maintenance Expense

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Increase (Decrease)	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	Increase (Decrease)
Operating and Maintenance Expense — Baseline	$ 160	$ 161	$ (1)	$ 303	$ 356	$ (53)
Operating and Maintenance Expense — Regulatory Required Programs(a)	—	—	—	—	—	—
Total Operating and Maintenance Expense	$ 160	$ 161	$ (1)	$ 303	$ 356	$ (53)

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for the three and six months ended June 30, 2013 compared to the same periods in 2012, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Baseline		
Charitable contributions accrual(a)	$ —	$ (28)
Merger costs(b)	(1)	(19)
Corporate Allocations	(3)	(5)
Storm-related costs	(3)	5
Labor, other benefits, contracting and materials	8	4
Other	(2)	(10)
	(1)	(53)
Regulatory Required Programs		
SOS	—	—
Decrease in operating and maintenance expense	$ (1)	$ (53)

(a) In accordance with the MDPSC order approving Exelon’s merger with Constellation, the charitable contribution accrual is not recoverable from BGE’s customers.
(b) BGE established a regulatory asset of $6 million at March 31, 2013 for certain 2012 other merger integration costs as part of the 2013 electric and gas distribution rate case order.

Depreciation and Amortization

The increase in depreciation and amortization expense for the three and six months ended June 30, 2013 compared to the same periods in 2012 was primarily due to higher amortization expense related to energy efficiency and demand response programs, which are fully offset in revenues above. Furthermore, higher expense is also due to higher property, plant and equipment balances resulting from ongoing capital expenditures.

Taxes Other Than Income

The increase in taxes other than income for the three and six months ended June 30, 2013 compared to the same periods in 2012 was primarily due to an increase in payroll taxes and increased GRT collections.

Interest Expense, Net

The decrease in interest expense, net for the three and six months ended June 30, 2013 compared to the same periods in 2012 was primarily due to interest recorded in 2012 on prior year tax liabilities.

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Other, Net

The decrease in other, net for the three and six months ended June 30, 2013 compared to the same periods in 2012 was primarily due to decreased AFUDC-Equity and investment income. See Note 19 – Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for further details of the components of other, net.

Effective Income Tax Rate

BGE's effective income tax rate was 39.0% and 36.0% for the three months ended June 30, 2013 and 2012, respectively, and 39.8% and 33.3% for the six months ended June 30, 2013 and 2012, respectively. See Note 12 – Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rate.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	% Change	Weather-Normal % Change	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)								
Residential	2,757	2,664	3.5%	n.m	6,293	5,865	7.3%	n.m
Small commercial & industrial	716	706	1.4%	n.m	1,492	1,435	4.0%	n.m
Large commercial & industrial	3,610	3,942	(8.4)%	n.m	7,164	7,582	(5.5)%	n.m
Public authorities & electric railroads	80	71	12.7%	n.m	161	158	1.9%	n.m
Total Electric Retail Deliveries	7,163	7,383	(3.0)%	n.m	15,110	15,040	0.5%	n.m

Number of Electric Customers	As of June 30, 2013	As of June 30, 2012
Residential	1,117,569	1,115,107
Small commercial & industrial	113,009	113,232
Large commercial & industrial	11,612	11,537
Public authorities & electric railroads	294	297
Total	1,242,484	1,240,173

Electric Revenue	Three Months Ended June 30, 2013	2012	% Change	Six Months Ended June 30, 2013	2012	% Change
Retail Delivery and Sales(a)						
Residential	$ 302	$ 295	2.4%	$ 667	$ 560	19.1%
Small commercial & industrial	60	60	0.0%	125	122	2.5%
Large commercial & industrial	112	99	13.1%	217	196	10.7%
Public authorities & electric railroads	8	7	14.3%	15	15	0.0%
Total Retail	482	461	4.6%	1,024	893	14.7%
Other Revenue	61	57	7.0%	124	114	8.8%
Total Electric Revenues	$ 543	$ 518	4.8%	$1,148	$1,007	14.0%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation suppliers as all customers are assessed delivery charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.

BGE Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended June 30, 2013	2012	% Change	Weather-Normal % Change	Six Months Ended June 30, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales(b)								
Retail sales	14,951	15,535	(3.8)%	n.m.	55,212	49,466	11.6%	n.m.
Transportation and other	1,545	4,854	(68.2)%	n.m.	7,195	10,295	(30.1)%	n.m.
Total Gas Deliveries	16,496	20,389	(19.1)%	n.m.	62,407	59,761	4.4%	n.m.

Number of Gas Customers	As of June 30, 2013	2012
Residential	611,146	610,073
Commercial & industrial	44,059	44,011
Total	655,205	654,084

Gas Revenue	Three Months Ended June 30, 2013	2012	% Change	Six Months Ended June 30, 2013	2012	% Change
Retail Delivery and Sales						
Retail sales	$ 100	$ 84	19.0%	$ 345	$ 272	26.8%
Transportation and other(b)	10	14	(28.6)%	40	33	21.2%
Total Gas Revenues	$ 110	$ 98	12.2%	$ 385	$ 305	26.2%

(b) Transportation and other gas revenue includes off-system revenue of 1,545 mmcfs ($8 million) and 4,854 mmcfs ($12 million) for the three months ended June 30, 2013 and 2012, respectively, and 7,195 mmcfs ($32 million) and 10,295 mmcfs ($29 million) for the six months ended June 30, 2013 and 2012, respectively.

Liquidity and Capital Resources

Exelon and Generation prior year activity presented below includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through June 30, 2012. BGE prior year activity presented below includes its activity for the six months ended June 30, 2012.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, Exelon, Generation, ComEd, PECO and BGE have access to unsecured revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. The Registrants' revolving credit facilities expire between 2017 and 2018. In addition, Generation has $0.4 billion in bilateral facilities with banks. The bilateral facilities at Generation have expirations in January 2015, December 2015 and March 2016. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and issue letters of credit. See the "Credit Matters" section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO and BGE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 11 – Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

Cash Flows from Operating Activities

General

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

ComEd's, PECO's and BGE's cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO and BGE, gas distribution services. ComEd's, PECO's and BGE's distribution services are provided to an established and diverse base of retail customers. ComEd's, PECO's and BGE's future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 5 — Regulatory Matters and 18 – Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. Certain provisions of the law were applied in 2012 while others take effect in 2013. The estimated impacts of the law are reflected in the projected pension contributions below.

Exelon expects to contribute $255 million to its qualified pension plans in 2013, of which Generation, ComEd, PECO and BGE will contribute $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 $81 million in 2013, of which Generation, ComEd, PECO, and BGE will make payments of $7 million, $1 million, $1 million, and $2 million, respectively.

To the extent interest rates decline or the pension plans do not earn the expected asset return rates, annual pension contribution requirements in future years could increase and such increases could be significant, especially in years 2015 and beyond. Additionally, the contributions above could change if Exelon changes its pension funding strategy.

Unlike qualified pension plans, other postretirement plans are not subject to regulatory minimum contribution requirements. Exelon's management considers 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.

Tax Matters

The Registrants' future cash flows from operating activities may be affected by the following tax matters:

- Exelon expects to receive a Federal refund of approximately $325 million between 2013 and 2014 which will be paid to ComEd, PECO, BGE and Generation of approximately $320 million, $10 million, $20 million, and $40 million, respectively.
- Given the current economic environment, state and local governments are facing increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the six months ended June 30, 2013 and 2012:

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	Variance
Net income	$ 498	$ 490	$ 8
Add (subtract):			
Non-cash operating activities(a)	2,025	2,688	(663)
Pension and other postretirement benefit contributions	(284)	(90)	(194)
Income taxes	705	259	446
Changes in working capital and other noncurrent assets and liabilities(b)	(337)	(977)	640
Option premiums paid, net	(10)	(108)	98
Counterparty collateral (posted) received, net	(259)	451	(710)
Net cash flows provided by operations	$ 2,338	$ 2,713	$ (375)

(a) Represents depreciation, amortization and accretion, impairment of long-lived assets, mark-to-market gains and losses on derivative transactions, deferred income taxes, provision for uncollectible accounts, pension and other postretirement benefit expense, equity in losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense and other non-cash charges.

(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

Cash flows provided by operations for the six months ended June 30, 2013 and 2012 by Registrant were as follows:

	Six Months Ended June 30,	
	2013	2012
Exelon	$ 2,338	$ 2,713
Generation	1,150	1,866
ComEd	503	722
PECO	467	409
BGE	366	353

Changes in Exelon's, Generation's, ComEd's, PECO's and BGE's cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business. In addition, significant operating cash flow impacts for the Registrants for the six months ended June 30, 2013 and 2012 were as follows:

Generation

- During the six months ended June 30, 2013 and 2012, Generation had net (payments) receipts of counterparty collateral of $(303) million and $443 million, respectively. Net (payments) receipts during the six months ended June 30, 2013 and 2012 were primarily due to market conditions that resulted in changes to Generation's net mark-to-market position. Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. This collateral may be in various forms, such as cash, which may be obtained through the issuance of commercial paper, or letters of credit.
- During the six months ended June 30, 2013 and 2012, Generation had net payments of approximately $(10) million and $(108) million, respectively, related to purchases and sales of options. The level of option activity in a given period may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During the six months ended June 30, 2013 and 2012, ComEd's net payables to Generation for energy purchases related to its supplier forward contract, ICC-approved RFP contracts and financial swap contract settlements decreased by $14 million and $10 million, respectively. During the six months ended June 30, 2013 and 2012, ComEd's payables to other energy suppliers for energy purchases increased by $31 million and $22 million, respectively.
- During the six months ended June 30, 2013 and 2012, ComEd received $45 million and $7 million, respectively, of incremental cash collateral from PJM. ComEd's collateral posted with PJM has decreased due to lower PJM billings resulting from lower load being served by ComEd due to increased switching activity primarily driven by municipal aggregation. As of June 30, 2013 and 2012, ComEd had $8 million and $84 million, respectively, of collateral posted with PJM.

PECO

- During the six months ended June 30, 2013 and 2012, PECO's payables to Generation for energy purchases decreased by $11 million and increased by $21 million, respectively, and payables to other electric and gas suppliers for energy purchases increased by $26 million and decreased by $31 million, respectively.

BGE

- During the six months ended June 30, 2013 and 2012, BGE's payables to Generation for energy purchases increased by $8 million and $6 million, respectively, and payables to other electric and gas suppliers for energy purchases increased by $2 million and decreased by $7 million, respectively.

Cash Flows from Investing Activities

Cash flows used in investing activities for the six months ended June 30, 2013 and 2012 by Registrant were as follows:

	Six Months Ended June 30,	
	2013	2012
Exelon	$(2,549)	$(1,968)
Generation	(1,378)	(1,284)
ComEd	(693)	(567)
PECO	(514)	(157)
BGE	(257)	(268)

Capital expenditures by Registrant for the six months ended June 30, 2013 and 2012 and projected amounts for the full year 2013 are as follows:

	Projected Full Year 2013 (d)	Six Months Ended June 30,	
		2013	2012
Exelon	$ 5,525	$ 2,518	$ 2,800
Generation(a)	2,775	1,277	1,820
ComEd(b)	1,450	711	585
PECO	575	254	179
BGE	650	264	266
Other(c)	75	12	30

(a) Includes nuclear fuel.
(b) The projected capital expenditures include approximately $267 million of expected incremental spending pursuant to EIMA, which ComEd has committed to invest approximately $2.6 billion over a ten year period to modernize and storm-harden its distribution system and to implement smart grid technology.
(c) Other primarily consists of corporate operations and BSC.
(d) Total projected capital expenditures do not include adjustments for non-cash activity.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Generation

Approximately 36% and 21% of the projected 2013 capital expenditures at Generation are for the acquisition of nuclear fuel and investments in renewable energy generation, including Antelope Valley construction costs, respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Also included in the projected 2013 capital expenditures are a portion of the costs of a series of planned power uprates across Generation's nuclear fleet, adjusted during the second quarter of 2013 to reflect the cancellation of certain nuclear power uprate projects during 2013. See "EXELON CORPORATION—Executive Overview," for more information on nuclear uprates.

ComEd, PECO and BGE

Approximately 90%, 89% and 78% of the projected 2013 capital expenditures at ComEd, PECO and BGE, respectively, are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA, and ComEd's, PECO's and BGE's construction commitments under PJM's RTEP. ComEd's capital expenditures includes smart grid/smart meter technology required under EIMA and for PECO and BGE capital expenditures related to its smart meter program and SGIG project, net of DOE expected reimbursements. The remaining amounts are for capital additions to support new business and customer growth.

In 2010, NERC provided guidance to transmission owners that recommends ComEd, PECO and BGE perform assessments of all their transmission lines, with the highest priority lines assessed by December 31, 2011, medium priority lines by December 31, 2012, and the lowest priority lines by December 31, 2013. In compliance with this guidance, ComEd, PECO and BGE submitted their most recent bi-annual reports to NERC in July 2013. ComEd, PECO and BGE will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2013 capital expenditures above reflect capital spending for remediation to be completed in 2013.

ComEd, PECO and BGE anticipate that they will fund their capital expenditures with internally generated funds and borrowings, including ComEd's capital expenditures associated with EIMA as further discussed in Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the six months ended June 30, 2013 and 2012 by Registrant were as follows:

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Exelon	$ (284)	$ (412)
Generation	(221)	(148)
ComEd	139	(360)
PECO	(259)	(174)
BGE	259	(81)

Debt

See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants' debt issuances and retirements.

Dividends

Cash dividend payments and distributions during the six months ended June 30, 2013 and 2012 by Registrant were as follows:

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Exelon	$ 716	$ 824
Generation	474	891
ComEd	110	85
PECO	167	174
BGE(a)	6	6

(a) Relates to dividends paid on BGE's preference stock.

Revised Dividend Policy

On February 6, 2013, the Exelon Board of Directors approved a revised dividend policy which contemplates a regular $0.31 per share quarterly dividend on Exelon's common stock payable beginning in the second quarter of 2013 (or $1.24 per share on an annualized basis), subject to quarterly declarations by the Exelon Board of Directors.

First Quarter 2013 Dividend

On February 6, 2013, the Exelon Board of Directors declared a regular quarterly dividend, paid on March 8, 2013 of $0.525 per share on Exelon's common stock.

Second Quarter 2013 Dividend

On April 23, 2013, the Exelon Board of Directors declared a regular quarterly dividend, paid on June 10, 2013 of $0.310 per share on Exelon's common stock.

Short-Term Borrowings

During the six months ended June 30, 2013, ComEd issued $374 million of commercial paper and Generation issued $276 million of commercial paper and $12 million in short-term notes payable. During the six months ended June 30, 2012, Exelon issued $27 million of outstanding commercial paper, ComEd issued $178 million of commercial paper and Generation repaid $26 million in short-term notes payable.

Contributions from Parent/Member

During the six months ended June 30, 2013, there were no contributions from Parent/Member (Exelon). During the six months ended June 30, 2012, Exelon contributed $66 million to BGE to fund the after-tax amount of the residential customer rate credit as directed in the MDPSC order approving the merger transaction.

Other

For the six months ended June 30, 2013, other financing activities primarily consists of expenses paid related to the replacement of the Registrants' credit facilities. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information.

Credit Matters

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include $8.4 billion in aggregate total commitments of which $6.4 billion was available as of June 30, 2013, and of which no financial institution has more than 8% of the aggregate commitments. Exelon, Generation, ComEd, PECO and BGE had access to the commercial paper market during the second quarter of 2013 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A. RISK FACTORS of Exelon's 2012 Annual Report on Form 10-K for further information regarding the effects of uncertainty in the capital and credit markets or significant bank failures.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of June 30, 2013, it would have been required to provide incremental collateral of $1,878 million, which is well within its current available credit facility capacities of $4.1 billion, which includes $1,878 million of collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements. If ComEd lost its investment grade credit rating as of June 30, 2013, it would have been required to provide incremental collateral of $18 million, which is well within its current available credit facility capacity of $626 million, which takes into account commercial paper borrowings as of June 30, 2013. If PECO lost its investment grade credit rating as of June 30, 2013, it would be required to provide collateral of $1 million pursuant to PJM's credit policy and could have been required to provide collateral of $31 million related to its natural gas procurement contracts, which, in the aggregate, are well within PECO's current available credit facility capacity of $599 million. If BGE lost its investment grade credit rating as of June 30, 2013, it would have been required to provide collateral of $2 million pursuant to PJM's credit policy and could have been required to provide collateral of $86 million related to its natural gas procurement contracts, which, in the aggregate, are well within BGE's current available credit facility capacity of $600 million.

Exelon Credit Facilities

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit. See Note 11 — Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for further information regarding the Registrants' credit facilities.

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at June 30, 2013:

Commercial Paper Programs

Commercial Paper Issuer	Maximum Program Size	Outstanding Commercial Paper at June 30, 2013	Average Interest Rate on Commercial Paper Borrowings for the Six Months Ended June 30, 2013
Exelon Corporate	$ 500	$ —	—
Generation	5,600	276	0.33%
ComEd	1,000	374	0.39%
PECO	600	—	—
BGE	600	—	—

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of its commercial paper outstanding does not reduce available capacity under a Registrant's credit agreement, a Registrant does not issue commercial paper in an aggregate amount exceeding the available capacity under its credit agreement.

Credit Agreements

Borrower	Facility Type	Aggregate Bank Commitment(a)	Facility Draws	Outstanding Letters of Credit	Available Capacity at June 30, 2013 Actual	To Support Additional Commercial Paper
Exelon Corporate	Syndicated Revolver	$ 500	$ —	$ 2	$ 498	$ 498
Generation	Syndicated Revolver	5,300	—	956	4,344	4,068
Generation	Bilaterals	375	—	374	1	1
ComEd	Syndicated Revolver	1,000	—	—	1,000	626
PECO	Syndicated Revolver	600	—	1	599	599
BGE	Syndicated Revolver	600	—	—	600	600

(a) Excludes $123 million of credit facility agreements arranged with minority and community banks at Generation, ComEd, PECO and BGE. These facilities expire on October 18, 2013, and are solely utilized to issue letters of credit. See Note 11 of the Combined Notes to the Consolidated Financial Statements for further information.

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.

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 registrants 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 agreement also requires each entity to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of each entity.

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 June 10, 2013, Exelon Corporate, Generation, PECO and BGE began the process of extending their respective unsecured syndicated revolving credit facilities, with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively. The transactions are expected to close and become effective in August 2013, with maturities of five years from the close of the transactions. The new covenants are expected to be substantially consistent with existing covenants. Generally, it is expected that costs incurred to amend and extend the facilities will be amortized over the newly extended lives of the facilities.

Each revolving credit agreement for Exelon, Generation, ComEd, PECO and BGE requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The following table summarizes the minimum thresholds reflected in the credit agreements for the six months ended June 30, 2013:

	Exelon	Generation	ComEd	PECO	BGE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

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At June 30, 2013, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	7.85	13.05	2.58	8.56	6.31

An event of default under any Registrant's credit facility will not constitute an event of default under any of the other Registrants' credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation under its credit facility will constitute an event of default under the Exelon corporate credit facility.

Security Ratings

The Registrants' access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants' borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant's securities could increase fees and interest charges under that Registrant's credit agreements.

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, Exelon operates an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant during the six months ended June 30, 2013, in addition to the net contribution or borrowing as of June 30, 2013, are presented in the following table:

Contributed (borrowed) as of June 30, 2013	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Generation	$ —	$ 417	$ (263)
PECO	298	—	263
BSC	—	194	(116)
Exelon Corporate	205	N/A	116

Investments in Nuclear Decommissioning Trust Funds

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation's NDT fund investment policy. Generation's investment policy establishes limits on the concentration of holdings in any one company and also in any one industry. See Note 13 – Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC's minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements

On May 29, 2012, the Registrants filed a combined shelf registration statement unlimited in amount, with the SEC, which became immediately effective and remained effective as of June 30, 2013. The ability of each Registrant to sell securities off shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations

On March 1, 2013, ComEd received $470 million in long-term debt new money authority from the ICC and on February 27, 2012, ComEd received $1.3 billion in long-term debt refinancing authority from the ICC. As of June 30, 2013, ComEd had $1.3 billion available in long-term debt refinancing authority and $568 million available in new money long-term debt financing authority from the ICC. As of June 30, 2013, PECO had $1.9 billion available in long-term debt financing authority from the PAPUC. As of June 30, 2013, BGE had $850 million available in long-term financing authority from MDPSC.

As of June 30, 2013, ComEd and PECO had short-term financing authority from FERC, which expires on December 31, 2013, of $2.5 billion and $1.5 billion, respectively. BGE had short-term financing authority from FERC, which expires December 31, 2014, of $0.7 billion. Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.

Contractual Obligations and Off-Balance Sheet Arrangements

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments triggered by future events. See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' commitments.

Generation, ComEd, PECO and BGE have obligations related to contracts for the purchase of power and fuel supplies, and ComEd, PECO and BGE have obligations related to their financing trusts. The power and fuel purchase contracts and the financing trusts have been considered for consolidation in the Registrants' respective financial statements pursuant to the authoritative guidance for VIEs. See Note 1 — Basis of Presentation of the Combined Notes to Consolidated Financial Statements for further information.

For an in-depth discussion of the Registrant's contractual obligations and off-balance sheet arrangements, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations and Off-Balance Sheet Arrangements" in the Exelon 2012 Form 10-K.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief executive officer, 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 Risk Oversight Committee of the Exelon Board of Directors on the scope of the risk management activities. The following discussion serves as an update to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of the Registrants' 2012 Annual Report on Form 10-K incorporated herein by reference.

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

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel, and other commodities.

Generation

Normal Operations and Hedging Activities. Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of ComEd's, PECO's and BGE's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2013 through 2015. Generation's energy contracts are accounted for under the accounting guidance for derivatives as further discussed in Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Generation hedges commodity risk on a ratable basis over the three years leading to the spot market. As of June 30, 2013, the percentage of expected generation hedged for the major reportable segments was 96%-99%, 78%-81% and 41%-44% 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 sales to ComEd, PECO and BGE to serve their retail load.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire non-trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on June 30, 2013 market conditions and hedged position would be an immaterial change in pre-tax income for 2013 and a decrease in pre-tax net income of approximately $260 million and $690 million, respectively, for 2014 and 2015. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio.

Proprietary Trading Activities. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 1,995 GWhs and 3,567 GWhs for the three and six months ended June 30, 2013, respectively, and 4,248 GWhs and 6,077 GWhs for the three and six months ended June 30, 2012, respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Trading portfolio activity for the six months ended June 30, 2013 resulted in pre-tax gains of $12 million due to net mark-to-market gains of $5 million and realized gains of $7 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $ 1.2 million of exposure during the quarter. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation's total gross margin from continuing operations for the six months ended June 30, 2013 of $3,489 million.

Fuel Procurement. Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained primarily through long-term contracts for uranium concentrates, and long-term contracts for conversion services, enrichment services and fuel fabrication services. The supply markets for coal, natural gas, uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2013 through 2017 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial positions. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information regarding uranium and coal supply agreement matters.

ComEd

The financial swap contract between Generation and ComEd was deemed prudent by the Illinois Settlement Legislation, thereby ensuring that ComEd would be entitled to receive full cost recovery in rates. The change in fair value each period was recorded by ComEd with an offset to a regulatory asset or liability. This financial swap contract between Generation and ComEd expired on May 31, 2013. All realized impacts have been included in Generation's and ComEd's results of operations.

ComEd's RFP contracts are deemed to be derivatives that qualify for the normal purchases and normal sales exception under derivative accounting guidance. ComEd does not enter into derivatives for speculative or trading purposes. ComEd is permitted full recovery of its RFP contracts from retail customers with no mark-up.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. 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 Notes 5 and 10 of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

PECO

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 5 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements. PECO has certain full requirements contracts and block contracts that are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

PECO has also entered into derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge its long-term price risk in the natural gas market. PECO's hedging program for natural gas procurement has no direct impact on its financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

BGE

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE's MDPSC-approved SOS program. BGE's full requirements contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE's financial position. However, under BGE's market-based rates incentive mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers.

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities. The following detailed presentation of Exelon's, Generation's, ComEd's and PECO's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon's, Generation's and ComEd's mark-to-market net asset or liability balance sheet position from December 31, 2012 to June 30, 2013. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings as well as the settlements from OCI to earnings and changes in fair value for the cash flow hedging activities that are recorded in accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 10 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of June 30, 2013 and December 31, 2012.

	Generation	ComEd	Intercompany Eliminations(b)	Exelon
Total mark-to-market energy contract net assets (liabilities) at December 31, 2012(a)	$ 1,505	$ (293)	$ —	$1,212
Total change in fair value during 2013 of contracts recorded in result of operations	44	—	(6)	38
Reclassification to realized at settlement of contracts recorded in results of operations	(14)	—	13	(1)
Reclassification to realized at settlement from accumulated OCI(c)	(459)	—	219	(240)
Changes in fair value — energy derivatives(d)	—	208	(226)	(18)
Changes in allocated collateral	297	—	—	297
Changes in net option premium paid/(received)	10	—	—	10
Option premium amortization(e)	(65)	—	—	(65)
Other balance sheet reclassifications	3	—	—	3
Total mark-to-market energy contract net assets (liabilities) at June 30, 2013(a)	$ 1,321	$ (85)	$ —	$1,236

(a) Amounts are shown net of collateral paid to and received from counterparties.

(b) Amounts related to five-year financial swap between Generation and ComEd are eliminated in consolidation.

(c) For Generation, includes $ 219 million of losses from reclassifications from accumulated OCI to recognize gains in net income related to settlement of the five-year financial swap contract with ComEd for the six months ended June 30, 2013.

(d) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of June 30, 2013, ComEd recorded an $85 million regulatory asset related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. As of June 30, 2013, this included $11 million of decreases in fair value and $215 million for reclassifications from regulatory asset to recognize cost in purchased power expense due to settlements of ComEd's five-year financial swap with Generation. As of June 30, 2013, ComEd also recorded $20 million of increases in fair value and $4 million of realized losses due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.

(e) Includes $65 million of amounts reclassified to realized at the settlement of contracts recorded to results of operations related to option premiums due to the settlement of the underlying transactions for the six months ended June 30, 2013.

Fair Values. The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities), net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 9 – Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

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Exelon

	Maturities Within						
	2013	2014	2015	2016	2017	2018 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts(a)(b):							
Actively quoted prices (Level 1)	$ (20)	$ (50)	$ (30)	$14	$ 2	$ —	$ (84)
Prices provided by external sources (Level 2)	243	483	147	16	—	—	889
Prices based on model or other valuation methods (Level 3)(c)	106	175	102	45	23	(20)	431
Total	$329	$608	$219	$75	$25	$ (20)	$ 1,236

(a) Mark-to-market gains and losses on economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $328 million at June 30, 2013.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2013	2014	2015	2016	2017	2018 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts(a)(b) :							
Actively quoted prices (Level 1)	$ (20)	$ (50)	$ (30)	$14	$ 2	$ —	$ (84)
Prices provided by external sources (Level 2)	243	483	147	16	—	—	889
Prices based on model or other valuation methods (Level 3)	122	184	119	61	37	(7)	516
Total	$345	$617	$236	$91	$39	$ (7)	$ 1,321

(a) Mark-to-market gains and losses on economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $328 million at June 30, 2013.

ComEd

	Maturities Within						
	2013	2014	2015	2016	2017	2018 and beyond	Total Fair Value
Prices based on model or other valuation methods(a)	$(16)	$ (9)	$(17)	$(16)	$(14)	$ (13)	$ (85)

(a) Represents ComEd's net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

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

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 10 – Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detail discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of June 30, 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 and an indication of the duration of a company's credit risk by credit rating of the 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, which are discussed below. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $41 million, $44 million and $33 million, respectively. See Note 22 – Related Party Transactions of the Exelon 2012 Form 10-K for further information.

Rating as of June 30, 2013	Total Exposure Before Credit Collateral	Credit Collateral(a)	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,744	$ 139	$ 1,605	1	$ 462
Non-investment grade	40	31	9	—	—
No external ratings					
Internally rated — investment grade	456	5	451	1	247
Internally rated — non-investment grade	62	1	61	—	—
Total	$ 2,302	$ 176	$ 2,126	2	$ 709

Rating as of June 30, 2013	Maturity of Credit Risk Exposure Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 1,235	$ 328	$ 181	$ 1,744
Non-investment grade	23	17	—	40
No external ratings				
Internally rated — investment grade	295	155	6	456
Internally rated — non-investment grade	62	—	—	62
Total	$ 1,615	$ 500	$ 187	$ 2,302

Net Credit Exposure by Type of Counterparty	As of June 30, 2013
Investor-owned utilities, marketers and power producers	$ 761
Energy cooperatives and municipalities	926
Financial institutions	386
Other	53
Total	$ 2,126

(a) As of June 30, 2013, credit collateral held from counterparties where Generation had credit exposure included $145 million of cash and $31 million of letters of credit.

ComEd

There have been no significant changes or additions to ComEd's exposures to credit risk that are described in ITEM 1A. RISK FACTORS of Exelon's 2012 Annual Report on Form 10-K.

See Note 10 of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

PECO

There have been no significant changes or additions to PECO's exposures to credit risk as described in ITEM 1A. RISK FACTORS of Exelon's 2012 Annual Report on Form 10-K.

See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

BGE

There have been no significant changes or additions to BGE's exposures to credit risk as described in ITEM 1A. RISK FACTORS of Exelon's 2012 Annual Report on Form 10-K.

See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

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

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, fossil fuel and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 10 of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation sells output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial position. As market prices rise above contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information.

As of June 30, 2013, Generation had $546 million cash collateral deposit payments being held by counterparties and Generation was holding $215 million of cash collateral deposits received from counterparties, of which $328 million in net cash collateral deposits was offset against mark-to-market assets and liabilities. As of June 30, 2013, $3 million of cash collateral posted was not offset against net derivative positions because it was not associated with energy-related derivatives. See Note 18 of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

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ComEd

As of June 30, 2013, ComEd held immaterial amounts of cash and letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts and held approximately $19 million in the form of cash and letters of credit for both annual and long-term renewable energy contracts. See Notes 5 — Regulatory Matters and 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for further information.

PECO

As of June 30, 2013, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 10 – Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for further information.

BGE

BGE is not required to post collateral under its electric supply contracts. As of June 30, 2013, BGE was not required to post collateral under its natural gas procurement contracts, nor was it holding collateral under its electric supply and natural gas procurement contracts. See Note 10 of the Combined Notes to Consolidated Financial Statements for further information.

RTOs and ISOs (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd, PECO and BGE participate in all, or some, of the established, real-time energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

Exchange Traded Transactions (Exelon and Generation)

Generation enters into commodity transactions on NYMEX, ICE and the Nodal exchange. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk.

Long-Term Leases (Exelon)

Exelon's consolidated balance sheets, as of June 30, 2013, included a $683 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of $1,465 million, less unearned income of $782 million. 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. Lessee performance under the lease agreements is supported by collateral and credit enhancement measures. Management regularly evaluates the creditworthiness of Exelon's counterparties to these long-term leases. Exelon monitors the continuing credit quality of the credit enhancement party.

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, if the review indicates a fair value below the carrying value and the decline is determined to be other than temporary, must record an impairment charge in the period the estimate changed. 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 in the net investment in direct financing leases of $14 million. See Note 7 of the Combined Notes to Consolidated Financial Statements for further information.

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

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At June 30, 2013, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and $570 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 PECO Accounts Receivables Facility) and fixed-to-floating swaps would result in less than $1 million decrease in Exelon Consolidated pre-tax income for the six months ended June 30, 2013.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. As of June 30, 2013, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $437 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

Item 4. Controls and Procedures

During the second quarter of 2013, each of Exelon's, Generation's, ComEd's, PECO's and BGE's management, including its principal executive officer and principal financial officer, evaluated its disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in its periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by all Registrants to ensure that (a) material information relating to that Registrant, including its consolidated subsidiaries, is accumulated and made known to Exelon's management, including its principal executive officer and principal financial officer, by other employees of that Registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of June 30, 2013, the principal executive officer and principal financial officer of each of Exelon, Generation, ComEd, PECO and BGE concluded that such Registrant's disclosure controls and procedures were effective to accomplish its objectives. All Registrants continually strive to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. In May 2013, the legacy-Constellation businesses transitioned to Exelon's enterprise-wide information technology networks and finance, supply chain and human resource systems, processes and controls; primarily impacting Exelon, Generation and BGE. Integration of Generation's commercial business platforms is being implemented in phases through mid-2014. Other than these changes, there have been no changes in internal control over financial reporting that occurred during the second quarter of 2013 that have materially affected, or are reasonably likely to materially affect, any of Exelon's, Generation's, ComEd's, PECO's and BGE's internal control over financial reporting.

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PART II — OTHER INFORMATION

Item 1. Legal Proceedings

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see (a) ITEM 3. LEGAL PROCEEDINGS of Exelon's 2012 Form 10-K and (b) Notes 4, 5 and 18 of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report. Such descriptions are incorporated herein by these references.

Item 1A. Risk Factors

Risks Related to Exelon

At June 30, 2013, the Registrants' risk factors were consistent with the risk factors described in Exelon's 2012 on Form 10-K.

Item 4. Mine Safety Disclosures

Exelon, Generation, ComEd, PECO and BGE

Not applicable to the Registrants.

Item 6. Exhibits

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
4.1	Form of 3.35% Senior Note due 2023. (File 1-1910, Form 8-K dated June 17, 2013, Exhibit 4.1)
101.INS*	XBRL Instance
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation
101.DEF*	XBRL Taxonomy Extension Definition
101.LAB*	XBRL Taxonomy Extension Labels
101.PRE*	XBRL Taxonomy Extension Presentation

* XBRL information will be considered to be furnished, not filed, for the first two years of a company's submission of XBRL information.

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Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2013 filed by the following officers for the following companies:

31-1	— Filed by Christopher M. Crane for Exelon Corporation
31-2	— Filed by Jonathan W. Thayer for Exelon Corporation
31-3	— Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
31-4	— Filed by Bryan P. Wright for Exelon Generation Company, LLC
31-5	— Filed by Anne R. Pramaggiore for Commonwealth Edison Company
31-6	— Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
31-7	— Filed by Craig L. Adams for PECO Energy Company
31-8	— Filed by Phillip S. Barnett for PECO Energy Company
31-9	— Filed by Kenneth W. DeFontes, Jr. for Baltimore Gas and Electric Company
31-10	— Filed by Carim V. Khouzami for Baltimore Gas and Electric Company

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes — Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2013 filed by the following officers for the following companies:

32-1	— Filed by Christopher M. Crane for Exelon Corporation
32-2	— Filed by Jonathan W. Thayer for Exelon Corporation
32-3	— Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
32-4	— Filed by Bryan P. Wright for Exelon Generation Company, LLC
32-5	— Filed by Anne R. Pramaggiore for Commonwealth Edison Company
32-6	— Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
32-7	— Filed by Craig L. Adams for PECO Energy Company
32-8	— Filed by Phillip S. Barnett for PECO Energy Company
32-9	— Filed by Kenneth W. DeFontes, Jr. for Baltimore Gas and Electric Company
32-10	— Filed by Carim V. Khouzami for Baltimore Gas and Electric Company

SIGNATURES

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON CORPORATION

/s/ CHRISTOPHER M. CRANE	/s/ JONATHAN W. THAYER
Christopher M. Crane President and Chief Executive Officer (Principal Executive Officer)	Jonathan W. Thayer Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ DUANE M. DESPARTE	
Duane M. DesParte Senior Vice President and Corporate Controller (Principal Accounting Officer)	

August 7, 2013

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON GENERATION COMPANY, LLC

/s/ KENNETH W. CORNEW	/s/ BRYAN P. WRIGHT
Kenneth W. Cornew President and Chief Executive Officer (Principal Executive Officer)	Bryan P. Wright Chief Financial Officer (Principal Financial Officer)
/s/ ROBERT M. AIKEN	
Robert M. Aiken Chief Accounting Officer (Principal Accounting Officer)	

August 7, 2013

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

COMMONWEALTH EDISON COMPANY

/s/ ANNE R. PRAMAGGIORE	/s/ JOSEPH R. TRPIK, JR.
Anne R. Pramaggiore President and Chief Executive Officer (Principal Executive Officer)	Joseph R. Trpik, Jr. Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ GERALD J. KOZEL	
Gerald J. Kozel Vice President and Controller (Principal Accounting Officer)	

August 7, 2013

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PECO ENERGY COMPANY

/s/ CRAIG L. ADAMS	/s/ PHILLIP S. BARNETT
Craig L. Adams President and Chief Executive Officer (Principal Executive Officer)	Phillip S. Barnett Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ SCOTT A. BAILEY	
Scott A. Bailey Vice President and Controller (Principal Accounting Officer)	

August 7, 2013

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ KENNETH W. DEFONTES, JR.	/s/ CARIM V. KHOUZAMI
Kenneth W. DeFontes, Jr. President and Chief Executive Officer (Principal Executive Officer)	Carim V. Khouzami Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ DAVID M. VAHOS	
David M. Vahos Vice President and Controller (Principal Accounting Officer)	

August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Christopher M. Crane, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ CHRISTOPHER M. CRANE
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Jonathan W. Thayer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JONATHAN W. THAYER

Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. Cornew, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ KENNETH W. CORNEW
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 7, 2013

Exhibit 31-4

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Bryan P. Wright, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

/s/ BRYAN P. WRIGHT
Chief Financial Officer
(Principal Financial Officer)

Date: August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Anne R. Pramaggiore, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ ANNE R. PRAMAGGIORE
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Joseph R. Trpik, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JOSEPH R. TRPIK, JR.
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: August 7, 2013

Exhibit 31-7

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Craig L. Adams, certify that:

1. I have reviewed this quarterly report on Form 10-Q of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ CRAIG L. ADAMS
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Phillip S. Barnett, certify that:

1. I have reviewed this quarterly report on Form 10-Q of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ PHILLIP S. BARNETT

Senior Vice President, Chief Financial Officer
and Treasurer
(Principal Financial Officer)

Date: August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. DeFontes, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ KENNETH W. DEFONTES, JR.
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Carim V. Khouzami, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ CARIM V. KHOUZAMI
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: August 7, 2013

Exhibit 32-1

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Corporation for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/s/ CHRISTOPHER M. CRANE

Christopher M. Crane
President and Chief Executive Officer

Date: August 7, 2013

Exhibit 32-2

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Corporation for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/s/ JONATHAN W. THAYER
Jonathan W. Thayer
Executive Vice President and Chief Financial Officer

Date: August 7, 2013

Exhibit 32-3

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Generation Company, LLC for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/s/ KENNETH W. CORNEW

Kenneth W. Cornew
President and Chief Executive Officer

Date: August 7, 2013

Exhibit 32-4

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Generation Company, LLC for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/s/ BRYAN P. WRIGHT
Bryan P. Wright
Chief Financial Officer

Date: August 7, 2013

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/s/ ANNE R. PRAMAGGIORE

Anne R. Pramaggiore
President and Chief Executive Officer

Date: August 7, 2013

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/s/ JOSEPH R. TRPIK, JR.
Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Date: August 7, 2013

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of PECO Energy Company for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/s/ CRAIG L. ADAMS
Craig L. Adams
President and Chief Executive Officer

Date: August 7, 2013

Exhibit 32-8

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of PECO Energy Company for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/s/ PHILLIP S. BARNETT
Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer

Date: August 7, 2013

Exhibit 32-9

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Baltimore Gas and Electric Company for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ KENNETH W. DEFONTES, JR.
Kenneth W. DeFontes, Jr.
President and Chief Executive Officer

Date: August 7, 2013

Exhibit 32-10

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Baltimore Gas and Electric Company for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ CARIM V. KHOUZAMI
Carim V. Khouzami
Senior Vice President, Chief Financial Officer and Treasurer

Date: August 7, 2013