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, 2012

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, 2012 was:

Exelon Corporation Common Stock, without par value	853,573,260
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,620
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's 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 Acquisitions Company, LLC
Enterprises	Exelon Enterprises Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
BondCo	RSB BondCo LLC
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
Registrants	Exelon, Generation, ComEd, PECO and BGE, collectively

Other Terms and Abbreviations	
Note "__" of the Exelon 2011 Form 10-K	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2011 Annual Report on Form 10-K
Act 11	Pennsylvania Act 11 of 2012
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
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
CAMR	Federal Clean Air Mercury Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
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
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
EDF	Electricite de France SA
EE&C	Energy Efficiency and Conservation/Demand Response
EGS	Electric Generation Supplier
EIMA	Illinois Senate Bill 1652 and Illinois House Bill 3036
EPA	United States Environmental Protection Agency

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
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
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.
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
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midwest Independent Transmission System Operator, Inc.
mmcf	Million Cubic Feet
Moody's	Moody's Investor Service
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
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

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
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
PCCA	Pennsylvania Climate Change Act
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
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
RMC	Risk Management Committee
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Services
SEC	United States Securities and Exchange Commission
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SERP	Supplemental Employee Retirement Plan
SFC	Supplier Forward Contract
SGIG	Smart Grid Investment Grant
SILO	Sale-In, Lease-Out
SMP	Smart Meter Program
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPP	Southwest Power Pool
SSCM	Simplified Service Cost Method
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
TEG	Termoelectrica del Golfo
TEP	Termoelectrica Penoles
Upstream	Natural gas exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

FILING FORMAT

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

FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this Report are 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 a Registrant include (a) those factors discussed in the following sections of Exelon's 2011 Annual Report on Form 10-K: ITEM 1A. Risk Factors, as updated by Part II, ITEM 1A of this Report; ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, as updated by Part I, ITEM 2. of this Report; and ITEM 8. Financial Statements and Supplementary Data: Note 18, as updated by Part I, Item 1. Financial Statements, Note 16 of this Report; (b) those factors discussed in the following sections of Constellation's 2011 Annual Report on Form 10-K: ITEM 1A. Risk Factors, as updated by Part II, ITEM 1A of this Report; ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, as updated by Part I, ITEM 2. of this Report; and ITEM 8. Financial Statements and Supplementary Data: Note 12, as updated by Part I, ITEM 1. Financial Statements, Note 16 of this Report; and (c) other factors discussed herein and in other 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

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

(In millions, except per share data)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Operating revenues	$ 5,954	$ 4,496	$10,640	$ 9,451
Operating expenses				
Purchased power and fuel	2,606	1,716	4,371	3,716
Operating and maintenance	1,829	1,226	3,793	2,449
Depreciation and amortization	494	329	876	656
Taxes other than income	254	191	448	394
Total operating expenses	5,183	3,462	9,488	7,215
Equity in loss of unconsolidated affiliates	(57)	—	(79)	—
Operating income	714	1,034	1,073	2,236
Other income and (deductions)				
Interest expense	(250)	(176)	(439)	(350)
Interest expense to affiliates, net	(6)	(6)	(12)	(13)
Other, net	(43)	101	152	196
Total other income and (deductions)	(299)	(81)	(299)	(167)
Income before income taxes	415	953	774	2,069
Income taxes	126	332	284	779
Net income	289	621	490	1,290
Net loss attributable to noncontrolling interests, preferred security dividends and preference stock dividends	3	1	4	2
Net income on common stock	286	620	486	1,288
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	(2)
Actuarial loss reclassified to periodic cost	41	34	82	66
Transition obligation reclassified to periodic cost	—	1	2	2
Pension and non-pension postretirement benefit plans valuation adjustment	(3)	—	(11)	39
Change in unrealized gain (loss) on cash flow hedges	(156)	(145)	59	(191)
Change in unrealized income on equity investments	6	—	6	—
Change in unrealized loss on foreign currency translation	(2)	—	(2)	—
Change in unrealized loss on marketable securities	(1)	—	—	—
Other comprehensive income (loss)	(114)	(111)	137	(86)
Comprehensive income	$ 175	$ 510	$ 627	$ 1,204
Average shares of common stock outstanding:				
Basic	853	663	779	663
Diluted	856	664	781	664
Earnings per average common share:				
Basic	$ 0.34	$ 0.93	$ 0.62	$ 1.94
Diluted	$ 0.33	$ 0.93	$ 0.62	$ 1.94
Dividends per common share	$ 0.53	$ 0.53	$ 1.05	$ 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, 2012	Six Months Ended June 30, 2011
Cash flows from operating activities		
Net income	$ 490	$ 1,290
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, accretion and depletion including nuclear fuel and energy contract amortization	1,895	1,114
Deferred income taxes and amortization of investment tax credits	227	590
Net fair value changes related to derivatives	(323)	264
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(70)	(51)
Other non-cash operating activities	959	378
Changes in assets and liabilities:		
Accounts receivable	414	—
Inventories	45	17
Accounts payable, accrued expenses and other current liabilities	(1,063)	(486)
Option premiums (paid) received, net	(108)	38
Counterparty collateral received (posted), net	451	(494)
Income taxes	259	691
Pension and non-pension postretirement benefit contributions	(90)	(2,089)
Other assets and liabilities	(357)	(249)
Net cash flows provided by operating activities	2,729	1,013
Cash flows from investing activities		
Capital expenditures	(2,816)	(1,985)
Proceeds from nuclear decommissioning trust fund sales	5,371	1,657
Investment in nuclear decommissioning trust funds	(5,483)	(1,772)
Cash acquired from Constellation	964	—
Proceeds from sales of investments	12	—
Purchases of investments	(5)	—
Change in restricted cash	(15)	(2)
Other investing activities	(12)	28
Net cash flows used in investing activities	(1,984)	(2,074)
Cash flows from financing activities		
Changes in short-term debt	179	140
Issuance of long-term debt	850	599
Retirement of long-term debt	(649)	(2)
Dividends paid on common stock	(773)	(695)
Dividends paid to former Constellation shareholders	(51)	—
Proceeds from employee stock plans	42	15
Other financing activities	(10)	(46)
Net cash flows (used in) provided by financing activities	(412)	11
Increase (decrease) in cash and cash equivalents	333	(1,050)
Cash and cash equivalents at beginning of period	1,016	1,612
Cash and cash equivalents at end of period	$ 1,349	$ 562

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EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2012 (Unaudited)	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,349	$ 1,016
Restricted cash and investments	83	40
Restricted cash and investments of variable interest entities	34	—
Accounts receivable, net		
Customer ($296 and $329 gross accounts receivable pledged as collateral as of June 30, 2012 and December 31, 2011, respectively)	2,886	1,613
Other	1,252	1,000
Accounts receivable, net, variable interest entities	183	—
Mark-to-market derivative assets	1,170	432
Unamortized energy contract assets	1,433	13
Inventories, net		
Fossil fuel	227	208
Materials and supplies	772	656
Deferred income taxes	63	—
Regulatory assets	867	390
Other	1,435	345
Total current assets	11,754	5,713
Property, plant and equipment, net	42,613	32,570
Deferred debits and other assets		
Regulatory assets	6,103	4,518
Nuclear decommissioning trust funds	6,841	6,507
Investments	836	751
Investments in affiliates	420	15
Investment in CENG	1,878	—
Goodwill	2,625	2,625
Mark-to-market derivative assets	1,241	650
Unamortized energy contracts assets	1,317	388
Pledged assets for Zion Station decommissioning	650	734
Other	1,156	524
Total deferred debits and other assets	23,067	16,712
Total assets	$ 77,434	$ 54,995

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2012 (Unaudited)	December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 376	$ 163
Short-term notes payable — accounts receivable agreement	225	225
Long-term debt due within one year	526	828
Long-term debt of variable interest entities due within one year	65	—
Accounts payable	2,183	1,444
Accounts payable of variable interest entities	119	—
Accrued expenses	1,452	1,255
Deferred income taxes	482	1
Regulatory liabilities	259	197
Dividends payable	4	349
Mark-to-market derivative liabilities	829	112
Unamortized energy contract liabilities	616	—
Other	947	560
Total current liabilities	8,083	5,134
Long-term debt	17,045	11,799
Long-term debt to financing trusts	649	390
Long-term debt of variable interest entity	479	—
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	10,823	8,253
Asset retirement obligations	4,126	3,884
Pension obligations	2,610	2,194
Non-pension postretirement benefit obligations	2,703	2,263
Spent nuclear fuel obligation	1,019	1,019
Regulatory liabilities	3,963	3,627
Mark-to-market derivative liabilities	578	126
Unamortized energy contract liabilities	747	—
Payable for Zion Station decommissioning	464	563
Other	1,736	1,268
Total deferred credits and other liabilities	28,769	23,197
Total liabilities	55,025	40,520
Commitments and contingencies		
Preferred securities of subsidiary	87	87
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 854 shares and 663 shares outstanding at June 30, 2012 and December 31, 2011, respectively)	16,559	9,107
Treasury stock, at cost (35 shares at June 30, 2012 and December 31, 2011, respectively)	(2,327)	(2,327)
Retained earnings	10,114	10,055
Accumulated other comprehensive loss, net	(2,313)	(2,450)
Total shareholders' equity	22,033	14,385
BGE preference stock not subject to mandatory redemption	193	—
Noncontrolling interest	96	3
Total equity	22,322	14,388
Total liabilities and shareholders' equity	$ 77,434	$ 54,995

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

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Non-controlling Interest	BGE preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2011	698,112	$ 9,107	$(2,327)	$10,055	$ (2,450)	$ 3	$ —	$14,388
Net income	—	—	—	486	—	(2)	6	490
Long-term incentive plan activity	2,080	87	—	—	—	—	—	87
Common stock dividends	—	—	—	(427)	—	—	—	(427)
Common stock issuance — Constellation merger	188,124	7,365	—	—	—	—	—	7,365
Noncontrolling interest acquired	—	—	—	—	—	95	—	95
BGE preference stock acquired	—	—	—	—	—	—	193	193
Preferred and preference stock dividends	—	—	—	—	—	—	(6)	(6)
Other comprehensive income net of income taxes of $(146)	—	—	—	—	137	—	—	137
Balance, June 30, 2012	888,316	$16,559	$(2,327)	$10,114	$ (2,313)	$ 96	$ 193	$22,322

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Operating revenues				
Operating revenues	$ 3,345	$ 2,209	$ 5,718	$ 4,546
Operating revenues from affiliates	408	246	774	552
Total operating revenues	3,753	2,455	6,492	5,098
Operating expenses				
Purchased power and fuel	1,852	841	2,896	1,724
Operating and maintenance	990	692	2,029	1,372
Operating and maintenance from affiliates	176	71	311	145
Depreciation and amortization	204	138	357	277
Taxes other than income	90	66	164	132
Total operating expenses	3,312	1,808	5,757	3,650
Equity in loss of unconsolidated affiliates	(57)	—	(79)	—
Operating income	384	647	656	1,448
Other income and (deductions)				
Interest expense	(85)	(45)	(138)	(91)
Other, net	(76)	76	103	152
Total other income and (deductions)	(161)	31	(35)	61
Income before income taxes	223	678	621	1,509
Income taxes	58	235	289	571
Net income	165	443	332	938
Net loss attributable to noncontrolling interests	(1)	—	(2)	—
Net income on membership interest	166	443	334	938
Other comprehensive income (loss), net of income taxes				
Change in unrealized loss on cash flow hedges	(266)	(254)	(14)	(323)
Change in unrealized income on equity investments	6	—	6	—
Change in unrealized loss on foreign currency translation	(2)	—	(2)	—
Change in unrealized loss on marketable securities	(1)	—	(1)	—
Other comprehensive loss	(263)	(254)	(11)	(323)
Comprehensive income (loss)	$ (98)	$ 189	$ 321	$ 615

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Six Months Ended June 30, 2012	2011
Cash flows from operating activities		
Net income	$ 332	$ 938
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	1,423	735
Deferred income taxes and amortization of investment tax credits	168	298
Net fair value changes related to derivatives	(307)	264
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(70)	(51)
Other non-cash operating activities	318	168
Changes in assets and liabilities:		
Accounts receivable	306	(139)
Receivables from and payables to affiliates, net	(42)	223
Inventories	30	(5)
Accounts payable, accrued expenses and other current liabilities	(732)	(78)
Option premiums (paid) received, net	(108)	38
Counterparty collateral received (paid), net	443	(525)
Income taxes	314	270
Pension and non-pension postretirement benefit contributions	(35)	(952)
Other assets and liabilities	(174)	(108)
Net cash flows provided by operating activities	1,866	1,076
Cash flows from investing activities		
Capital expenditures	(1,820)	(1,270)
Proceeds from nuclear decommissioning trust fund sales	5,371	1,657
Investment in nuclear decommissioning trust funds	(5,483)	(1,772)
Change in restricted cash	6	—
Cash acquired from Constellation	708	—
Other investing activities	(66)	(3)
Net cash flows used in investing activities	(1,284)	(1,388)
Cash flows from financing activities		
Issuance of long-term debt	850	—
Retirement of long-term debt	(56)	(1)
Change in short-term debt	(42)	—
Distribution to member	(891)	—
Other financing activities	(9)	(34)
Net cash flows used in financing activities	(148)	(35)
Increase (decrease) in cash and cash equivalents	434	(347)
Cash and cash equivalents at beginning of period	496	456
Cash and cash equivalents at end of period	$ 930	$ 109

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2012 (Unaudited)	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 930	$ 496
Restricted cash and cash equivalents	2	5
Restricted cash and cash equivalents, variable interest entities	12	—
Accounts receivable, net		
Customer	1,579	578
Other	254	257
Accounts receivable, net, variable interest entities	183	—
Mark-to-market derivative assets	1,170	432
Mark-to-market derivative assets with affiliates	506	503
Receivables from affiliates	144	109
Unamortized energy contract assets	1,433	13
Inventories, net		
Fossil fuel	134	120
Materials and supplies	628	556
Other	1,110	148
Total current assets	8,085	3,217
Property, plant and equipment, net	17,702	13,475
Deferred debits and other assets		
Nuclear decommissioning trust funds	6,841	6,507
Investments	82	41
Investments in affiliates	397	1
Investment in CENG	1,878	—
Mark-to-market derivative assets	1,227	635
Mark-to-market derivative assets with affiliates	—	191
Prepaid pension asset	2,057	2,068
Pledged assets for Zion Station decommissioning	650	734
Unamortized energy contract assets	1,317	388
Other	851	176
Total deferred debits and other assets	15,300	10,741
Total assets	$ 41,087	$ 27,433

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, 2012 (Unaudited)	December 31, 2011
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 10	$ 2
Long-term debt due within one year	23	3
Long-term debt due within one year of variable interest entities	3	—
Accounts payable	1,310	753
Accounts payable of variable interest entities	119	—
Accrued expenses	885	779
Payables to affiliates	115	58
Deferred income taxes	567	244
Mark-to-market derivative liabilities	810	103
Unamortized energy contract liabilities	506	—
Other	378	202
Total current liabilities	4,726	2,144
Long-term debt	7,163	3,674
Long-term debt of variable interest entities	180	—
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,892	3,966
Asset retirement obligations	3,997	3,767
Non-pension postretirement benefit obligations	815	703
Spent nuclear fuel obligation	1,019	1,019
Payables to affiliates	2,352	2,222
Mark-to-market derivative liabilities	485	29
Unamortized energy contract liabilities	696	—
Payable for Zion Station decommissioning	464	563
Other	793	638
Total deferred credits and other liabilities	15,513	12,907
Total liabilities	27,582	18,725
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	8,828	3,556
Undistributed earnings	3,675	4,232
Accumulated other comprehensive income, net	904	915
Total member's equity	13,407	8,703
Noncontrolling interest	98	5
Total equity	13,505	8,708
Total liabilities and equity	$ 41,087	$ 27,433

See the Combined Notes to Consolidated Financial Statements

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

	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Income, net	Noncontrolling Interest	Total Equity
Balance, December 31, 2011	$ 3,556	$ 4,232	$ 915	$ 5	$ 8,708
Net income	—	334	—	(2)	332
Acquisition of Constellation	5,272	—	—	—	5,272
Noncontrolling interest acquired	—	—	—	95	95
Distribution to member	—	(891)	—	—	(891)
Other comprehensive loss, net of income taxes of $4	—	—	(11)	—	(11)
Balance, June 30, 2012	$ 8,828	$ 3,675	$ 904	$ 98	$13,505

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, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Operating revenues				
Operating revenues	$ 1,280	$ 1,444	$ 2,669	$ 2,909
Operating revenues from affiliates	1	—	1	1
Total operating revenues	1,281	1,444	2,670	2,910
Operating expenses				
Purchased power	384	588	757	1,214
Purchased power from affiliate	203	128	451	291
Operating and maintenance	293	232	569	461
Operating and maintenance from affiliate	38	36	81	73
Depreciation and amortization	152	136	300	270
Taxes other than income	69	70	144	147
Total operating expenses	1,139	1,190	2,302	2,456
Operating income	142	254	368	454
Other income and (deductions)				
Interest expense	(71)	(82)	(150)	(164)
Interest expense to affiliates, net	(3)	(4)	(6)	(8)
Other, net	3	4	7	8
Total other income and (deductions)	(71)	(82)	(149)	(164)
Income before income taxes	71	172	219	290
Income taxes	29	58	90	107
Net income	42	114	129	183
Other comprehensive income, net of income taxes				
Change in unrealized gain on marketable securities	—	—	1	—
Other comprehensive income	—	—	1	—
Comprehensive income	$ 42	$ 114	$ 130	$ 183

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Six Months Ended June 30, 2012	2011
Cash flows from operating activities		
Net income	$ 129	$ 183
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	300	270
Deferred income taxes and amortization of investment tax credits	116	184
Other non-cash operating activities	241	115
Changes in assets and liabilities:		
Accounts receivable	(26)	(62)
Receivables from and payables to affiliates, net	(18)	(23)
Inventories	(7)	(7)
Accounts payable, accrued expenses and other current liabilities	(54)	(108)
Counterparty collateral received, net	8	31
Income taxes	149	321
Pension and non-pension postretirement benefit contributions	(12)	(871)
Other assets and liabilities	(104)	38
Net cash flows provided by operating activities	722	71
Cash flows from investing activities		
Capital expenditures	(585)	(495)
Proceeds from sales of investments	12	4
Purchases of investments	(5)	(2)
Other investing activities	11	20
Net cash flows used in investing activities	(567)	(473)
Cash flows from financing activities		
Changes in short-term debt	178	—
Issuance of long-term debt	—	599
Retirement of long-term debt	(450)	(1)
Dividends paid on common stock	(85)	(150)
Other financing activities	(3)	(2)
Net cash flows (used in) provided by financing activities	(360)	446
(Decrease) Increase in cash and cash equivalents	(205)	44
Cash and cash equivalents at beginning of period	234	50
Cash and cash equivalents at end of period	$ 29	$ 94

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2012 (Unaudited)	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 29	$ 234
Restricted cash	3	3
Accounts receivable, net		
Customer	675	655
Other	245	385
Inventories, net	88	81
Deferred income taxes	74	61
Counterparty collateral deposited	84	90
Regulatory assets	726	657
Other	23	22
Total current assets	1,947	2,188
Property, plant and equipment, net	13,428	13,121
Deferred debits and other assets		
Regulatory assets	583	699
Investments	15	21
Investments in affiliates	6	6
Goodwill	2,625	2,625
Receivables from affiliates	1,963	1,860
Prepaid pension asset	1,736	1,803
Other	282	315
Total deferred debits and other assets	7,210	7,329
Total assets	$ 22,585	$ 22,638

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2012 (Unaudited)	December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 178	$ —
Long-term debt due within one year	125	450
Accounts payable	349	325
Accrued expenses	244	318
Payables to affiliates	96	111
Customer deposits	138	136
Regulatory liabilities	146	137
Mark-to-market derivative liability	19	9
Mark-to-market derivative liability with affiliate	506	503
Other	117	82
Total current liabilities	1,918	2,071
Long-term debt	5,091	5,215
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,106	3,993
Asset retirement obligations	92	89
Non-pension postretirement benefits obligations	330	271
Regulatory liabilities	3,149	3,042
Mark-to-market derivative liability	92	97
Mark-to-market derivative liability with affiliate	—	191
Other	506	426
Total deferred credits and other liabilities	8,275	8,109
Total liabilities	15,490	15,601
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	5,016	5,003
Retained earnings	491	447
Accumulated other comprehensive loss, net	—	(1)
Total shareholders' equity	7,095	7,037
Total liabilities and shareholders' equity	$ 22,585	$ 22,638

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 Loss, net	Total Shareholders' Equity
Balance, December 31, 2011	$ 1,588	$ 5,003	$ (1,639)	$ 2,086	$ (1)	$ 7,037
Net income	—	—	129	—	—	129
Appropriation of retained earnings for future dividends	—	—	(129)	129	—	—
Common stock dividends	—	—	—	(85)	—	(85)
Allocation of tax benefit from parent	—	13	—	—	—	13
Other comprehensive income, net of income taxes of $0	—	—	—	—	1	1
Balance, June 30, 2012	$ 1,588	$ 5,016	$ (1,639)	$ 2,130	$ —	$ 7,095

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Operating revenues				
Operating revenues	$ 714	$ 842	$ 1,588	$ 1,994
Operating revenues from affiliates	1	—	2	2
Total operating revenues	715	842	1,590	1,996
Operating expenses				
Purchased power and fuel	171	293	472	785
Purchased power from affiliate	125	115	235	257
Operating and maintenance	146	150	318	334
Operating and maintenance from affiliates	26	22	57	44
Depreciation and amortization	54	50	107	98
Taxes other than income	42	51	74	106
Total operating expenses	564	681	1,263	1,624
Operating income	151	161	327	372
Other income and (deductions)				
Interest expense	(28)	(31)	(56)	(62)
Interest expense to affiliates, net	(3)	(3)	(6)	(6)
Other, net	2	3	5	8
Total other income and (deductions)	(29)	(31)	(57)	(60)
Income before income taxes	122	130	270	312
Income taxes	42	47	93	102
Net income	80	83	177	210
Preferred security dividends	1	1	2	2
Net income on common stock	79	82	175	208
Comprehensive income, net of income taxes				
Net income	80	83	177	210
Other comprehensive income, net of income taxes				
Change in unrealized gains on marketable securities	—	—	1	—
Other comprehensive income	—	—	1	—
Comprehensive income	$ 80	$ 83	$ 178	$ 210

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

(In millions)	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Cash flows from operating activities		
Net income	$ 177	$ 210
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	107	98
Deferred income taxes and amortization of investment tax credits	19	91
Other non-cash operating activities	66	44
Changes in assets and liabilities:		
Accounts receivable	62	221
Receivables from and payables to affiliates, net	9	(218)
Inventories	26	29
Accounts payable, accrued expenses and other current liabilities	(83)	(11)
Income taxes	121	113
Pension and non-pension postretirement benefit contributions	(8)	(110)
Other assets and liabilities	(87)	(108)
Net cash flows provided by operating activities	409	359
Cash flows from investing activities		
Capital expenditures	(179)	(209)
Changes in Exelon intercompany money pool	18	(171)
Change in restricted cash	(3)	(2)
Other investing activities	7	11
Net cash flows used in investing activities	(157)	(371)
Cash flows from financing activities		
Dividends paid on common stock	(172)	(184)
Dividends paid on preferred securities	(2)	(2)
Other financing activities	—	(5)
Net cash flows used in financing activities	(174)	(191)
Increase (decrease) in cash and cash equivalents	78	(203)
Cash and cash equivalents at beginning of period	194	522
Cash and cash equivalents at end of period	$ 272	$ 319

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2012 (Unaudited)	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 272	$ 194
Restricted cash and cash equivalents	5	2
Accounts receivable, net		
Customer ($296 and $329 gross accounts receivable pledged as collateral as of June 30, 2012 and December 31, 2011, respectively)	307	380
Other	230	376
Inventories, net		
Fossil fuel	58	87
Materials and supplies	21	18
Deferred income taxes	31	25
Receivable from Exelon intercompany money pool	64	82
Prepaid utility taxes	99	1
Regulatory assets	54	39
Other	50	39
Total current assets	1,191	1,243
Property, plant and equipment, net	5,960	5,874
Deferred debits and other assets		
Regulatory assets	1,216	1,216
Investments	21	22
Investments in affiliates	8	8
Receivable from affiliates	392	365
Prepaid pension asset	379	382
Other	37	46
Total deferred debits and other assets	2,053	2,039
Total assets	$ 9,204	$ 9,156

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2012 (Unaudited)	December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term notes payable — accounts receivable agreement	$ 225	$ 225
Long-term debt due within one year	375	375
Accounts payable	198	262
Accrued expenses	71	83
Payables to affiliates	77	62
Customer deposits	52	53
Regulatory liabilities	91	60
Other	34	25
Total current liabilities	1,123	1,145
Long-term debt	1,598	1,597
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,214	2,170
Asset retirement obligations	28	28
Non-pension postretirement benefits obligations	303	288
Regulatory liabilities	606	585
Other	119	134
Total deferred credits and other liabilities	3,270	3,205
Total liabilities	6,175	6,131
Commitments and contingencies		
Preferred securities	87	87
Shareholders' equity		
Common stock	2,379	2,379
Retained earnings	562	559
Accumulated other comprehensive income, net	1	—
Total shareholders' equity	2,942	2,938
Total liabilities and shareholders' equity	$ 9,204	$ 9,156

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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, 2011	$ 2,379	$ 559	$ —	$ 2,938
Net income	—	177	—	177
Common stock dividends	—	(172)	—	(172)
Preferred security dividends	—	(2)	—	(2)
Other comprehensive income, net of income taxes of $0	—	—	1	1
Balance, June 30, 2012	$ 2,379	$ 562	$ 1	$ 2,942

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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, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Operating revenues				
Operating revenues	$ 614	$ 672	$ 1,307	$ 1,647
Operating revenues from affiliates	2	2	5	3
Total operating revenues	616	674	1,312	1,650
Operating expenses				
Purchased power and fuel	201	267	494	753
Purchased power from affiliate	84	73	176	130
Operating and maintenance	135	129	288	249
Operating and maintenance from affiliates	26	38	68	70
Depreciation and amortization	71	67	150	144
Taxes other than income	47	46	95	96
Total operating expenses	564	620	1,271	1,442
Operating income	52	54	41	208
Other income and (deductions)				
Interest expense	(34)	(32)	(75)	(66)
Other, net	7	6	13	13
Total other income and (deductions)	(27)	(26)	(62)	(53)
Income (loss) before income taxes	25	28	(21)	155
Income taxes	9	12	(7)	58
Net income (loss)	16	16	(14)	97
Preference stock dividends	3	3	6	6
Net income (loss) on common stock	$ 13	$ 13	$ (20)	$ 91
Comprehensive income (loss)	$ 16	$ 16	$ (14)	$ 97

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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, 2012	2011
Cash flows from operating activities		
Net (loss) income	$ (14)	$ 97
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	150	144
Deferred income taxes and amortization of investment tax credits	91	59
Other non-cash operating activities	100	54
Changes in assets and liabilities:		
Accounts receivable	92	94
Receivables from and payables to affiliates, net	(3)	(10)
Inventories	37	7
Accounts payable, accrued expenses and other current liabilities	(71)	(24)
Income taxes	(48)	56
Pension and non-pension postretirement benefit contributions	(8)	(7)
Other assets and liabilities	43	3
Net cash flows provided by operating activities	369	473
Cash flows from investing activities		
Capital expenditures	(282)	(283)
Change in restricted cash	8	4
Other investing activities	(10)	—
Net cash flows used in investing activities	(284)	(279)
Cash flows from financing activities		
Repayment of long-term debt	(141)	(30)
Dividends paid on common stock	—	(85)
Dividends paid on preference stock	(6)	(6)
Contributions from parent	66	—
Other financing activities	—	(2)
Net cash flows used in financing activities	(81)	(123)
Increase in cash and cash equivalents	4	71
Cash and cash equivalents at beginning of period	49	50
Cash and cash equivalents at end of period	$ 53	$ 121

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2012 (Unaudited)	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 53	$ 49
Restricted cash and cash equivalents of variable interest entity	22	30
Accounts receivable, net		
Customer	324	428
Other	99	90
Income taxes receivable	67	21
Inventories, net		
Gas held in storage	35	74
Materials and supplies	36	34
Prepaid utility taxes	5	56
Regulatory assets	179	174
Other	8	12
Total current assets	828	968
Property, plant and equipment, net	5,294	5,132
Deferred debits and other assets		
Regulatory assets	550	550
Investments	5	—
Investments in affiliates	8	8
Prepaid pension asset	490	514
Other	25	33
Total deferred debits and other assets	1,078	1,105
Total assets	$ 7,200	$ 7,205

See the Combined Notes to Consolidated Financial Statements

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2012 (Unaudited)	December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long-term debt due within one year	$ —	$ 110
Long-term debt of variable interest entity due within one year	65	63
Accounts payable	161	210
Accrued expenses	110	148
Deferred income taxes	66	59
Payables to affiliates	44	41
Customer deposits	80	84
Regulatory liabilities	22	18
Other	59	25
Total current liabilities	607	758
Long-term debt	1,597	1,596
Long-term debt to financing trust	258	258
Long-term debt of variable interest entity	299	332
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,577	1,491
Asset retirement obligations	8	1
Non-pension postretirement benefits obligations	211	212
Regulatory liabilities	208	200
Other	88	56
Total deferred credits and other liabilities	2,092	1,960
Total liabilities	4,853	4,904
Commitments and contingencies		
Shareholders' equity		
Common stock	1,360	1,294
Retained earnings	797	817
Total shareholders' equity	2,157	2,111
Preference stock not subject to mandatory redemption	190	190
Total equity	2,347	2,301
Total liabilities and shareholders' equity	$ 7,200	$ 7,205

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2011	$ 1,294	$ 817	$ 2,111	$ 190	$ 2,301
Net loss	—	(14)	(14)	—	(14)
Preference stock dividends	—	(6)	(6)	—	(6)
Contribution from parent	66	—	66	—	66
Balance, June 30, 2012	$ 1,360	$ 797	$ 2,157	$ 190	$ 2,347

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 includes the former Constellation customer supply and generation businesses. BGE, formerly Constellation's regulated utility subsidiary, is now a subsidiary of Exelon. Refer to Note 3 — Merger and Acquisitions for further information regarding the merger transaction.

The energy generation business includes:

- *Generation*: The business consists of owned, contracted and investments in electric generating facilities and wholesale and retail customer supply of electric and natural gas products and services, including renewable energy products, risk management services and natural gas exploration and production activities.

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.

BGE was acquired through a transaction under common control (RF HoldCo LLC) and Exelon did not apply push-down accounting to BGE. As a result, BGE continues to maintain its current 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, 2012 and 2011 and the financial position as of June 30, 2012 and December 31, 2011. However, for Exelon's financial reporting, Exelon is reporting BGE activity from March 12, 2012 through June 30, 2012.

Each of Generation's, ComEd's, PECO's and BGE's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

The accompanying consolidated financial statements as of June 30, 2012 and 2011 and for the three and six months then ended are unaudited but, in the opinion of the management of each Registrant includes all adjustments that are considered necessary for a fair statement of its respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2011 Consolidated Balance Sheets were taken 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, PECO's and BGE's Consolidated Balance Sheets have been reclassified between line items for comparative purposes. The reclassifications did not affect any of the Registrants' net income or cash flows from operating activities. 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 2011 Form 10-K.

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

Consolidated Variable Interest Entities

The Registrants' 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;
- a group of solar project limited liability companies formed to build, own, and operate solar power facilities; and
- several wind projects designed to develop, construct and operate wind generation facilities.

See Note 1 and Note 4 of the 2011 Form 10-K for Constellation and BGE for further information regarding investments in VIEs.

For each of the consolidated VIEs:

- 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 for non-bypassable rate stabilization charges to BondCo. During the three and six months ended June 30, 2012, BGE remitted $15 million and $35 million, respectively, to BondCo. During the three and six months ended June 30, 2011, BGE remitted $16 million and $39 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 three and six months ended June 30, 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 or BGE's general credit.

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

At June 30, 2012, Exelon's, Generation's and BGE's consolidated financial statements include the following balances for consolidated VIEs, which were acquired as part of the merger:

	June 30, 2012		
	Exelon	Generation	BGE
Current assets	$ 355	$ 333	$ 22
Noncurrent assets	446	403	—
Total assets	$ 801	$ 736	$ 22
Current liabilities	$ 280	$ 210	$ 70
Noncurrent liabilities	553	212	299
Total liabilities	$ 833	$ 422	$369

Unconsolidated Variable Interest Entities

Exelon's and Generation's variable interests in unconsolidated VIEs generally include three categories: (1) equity method investments, (2) energy purchase and sale contracts, and (3) fuel purchase commitments. As of the balance sheet date, the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the majority of the energy contracts and fuel purchase contracts with VIEs are predominately related to working capital accounts and generally represent the amounts owed by Exelon and Generation for the deliveries associated with the current billing cycles under the contracts. Further, Exelon and Generation have not provided or guaranteed the debt or equity support, or liquidity arrangements, performance guarantees or other commitments associated with these contracts, so there is no significant potential exposure to loss as a result of the involvement with these VIEs.

As of June 30, 2012, Exelon and Generation did have exposure to loss associated with six VIEs for which they were not the primary beneficiary; including certain equity method investments and certain energy contracts. The following table presents summary information about the unconsolidated VIE entities for which Exelon and Generation have exposure to loss, which were added as a result of the merger:

June 30, 2012	Energy Contract VIEs	Equity Method Investment VIEs	Total
Total assets(a)	$ 283	$ 363	$646
Total liabilities(a)	220	116	336
Registrants' ownership interest(a)	—	98	98
Other ownership interests(a)	63	149	212
Registrants' maximum exposure to loss:			
Letters of credit	11	—	11
Carrying amount of equity method investments	—	77	77
Debt and payment guarantees	—	5	5

(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.

During the six months ended June 30, 2012, ComEd, PECO, BGE and Generation assessed their contracts and determined there were no changes in their variable interests, primary beneficiary determinations or conclusions regarding consolidation of VIEs from December 31, 2011. See Note 1 of the Exelon 2011 Form 10-K and Note 1 and Note 4 of the 2011 10-K for BGE for further information regarding the Registrants' VIEs.

RF HoldCo LLC, a bankruptcy-remote special purpose subsidiary holds all of Exelon's common equity interests in BGE. This subsidiary is not a VIE. However, due to Exelon's ownership of 100% of the voting interests of RF HoldCo LLC, Exelon consolidates this subsidiary as a voting interest entity.

BGE and RF HoldCo are separate legal entities and are not liable for the debts of Exelon. Accordingly, creditors of Exelon may not satisfy their debts from the assets of BGE and RF HoldCo LLC except as required by applicable law or regulation. Similarly, Exelon is not liable for the debts of BGE or RF HoldCo LLC. Accordingly, creditors of BGE and RF HoldCo LLC may not satisfy their debts from the assets of Exelon except as required by applicable law or regulation.

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

The following recently issued accounting standard was adopted by the Registrants during the period.

Fair Value Measurement

In May 2011, the FASB issued authoritative guidance amending existing guidance for measuring and disclosing fair value. The new guidance does not impact the fair value measurements included in the Registrants' Consolidated Financial Statements as of June 30, 2012. The guidance is effective for the Registrants beginning with the period ended March 31, 2012 and is required to be applied prospectively. See Note 7 — Fair Value of Financial Assets and Liabilities for the new disclosures.

3. Merger and Acquisitions

Merger with Constellation (Exelon, Generation 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 the customer supply and generation businesses that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger.

Constellation's shareholders received 0.930 shares of Exelon common stock in exchange for each share of Constellation common stock outstanding as of March 12, 2012. Generally, all outstanding Constellation equity-based compensation awards were converted into Exelon equity-based compensation awards using the same ratio. See Note 14 — Stock-Based Compensation Plans for further information.

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.

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

On February 17, 2012, the MDPSC approved the merger with conditions. Many of the conditions were reflective of the settlement agreements described above. The following costs were recognized after the closing of the merger and are included in Exelon's, Generation's and BGE's Consolidated Statements of Operations and Comprehensive Income for the six months ended June 30, 2012:

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.

In addition to these costs, the estimate of $1 billion of direct investment includes $95 million to $120 million for the requirement to cause construction of a headquarters building in Baltimore for Generation's competitive energy businesses. The construction is expected to be completed in 2 to 3 years. The $1 billion estimate also includes $625 million for Exelon and Generation's commitment to develop 285 – 300 MW of new generation in Maryland, expected to be completed over a period of 10 years. As of June 30, 2012, amounts reflected in the Exelon and Generation consolidated financial statements for these expenditure commitments were immaterial. Such costs, which are expected to be primarily capital in nature, will be recognized as incurred.

Pursuant to the MDPSC merger approval conditions, BGE is restricted from paying any dividend on its common shares through the end of 2014, is required to maintain specified minimum capital and O&M expenditure levels in 2012 and 2013, and is not permitted to reduce employment levels due to involuntary attrition associated with the merger integration process.

Associated with certain of the regulatory approvals required for the merger, Exelon and Constellation agreed to enter into contracts to sell three Constellation generating stations located in PJM within 150 days (subsequently extended 30 days by DOJ) following the merger completion and will be required to complete the divestitures within 30 days after receipt of regulatory approvals. These stations, Brandon Shores and H.A. Wagner in Anne Arundel County, Maryland, and C.P. Crane in Baltimore County, Maryland, include base-load, coal-fired generation units plus associated gas/oil units located at the same sites, and total 2,648 MW of generation capacity. In October 2011, Exelon and Constellation reached a settlement with the PJM Independent Market Monitor, who had previously raised market power concerns regarding the merger. The settlement contains a number of commitments by Exelon, including limiting the universe of potential buyers of the divested assets to entities without significant market shares in the relevant PJM markets. The settlement also includes assurances about how Generation will bid its units into the PJM markets. The proposed divestiture and the settlement with the PJM Market Monitor were filed with FERC and the MDPSC and were included in their final orders approving the merger.

As of June 30, 2012, these assets are classified as held for sale assets and included in the other current assets balance on Exelon's and Generation's Consolidated Balance Sheets. In accordance with ASC 820, these assets are valued at estimated fair value less costs to sell, whereby fair value is defined as the price that would be received to sell the assets in an orderly transaction between market participants.

On August 8, 2012, a subsidiary of Generation reached an agreement to sell these three Maryland generating stations and associated assets to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC. The transaction, which is subject to approval by FERC and DOJ, is expected to close in the fourth quarter 2012. The agreement includes a base price with purchase price adjustments based on fuel inventory, working capital, capital expenditures, and timing of the closing, resulting in an estimated sales price of approximately $400 million. Decisions by certain market participants to remove themselves from the bidding process, combined with the deadlines and limitations on the pool of potential buyers imposed by the merger approval orders, resulted in realized sales proceeds below the estimated fair value of the Maryland generating stations than would have been achieved in an orderly transaction. Therefore, Exelon and Generation will record a pre-tax loss estimated to be approximately $275 million in the third quarter of 2012 to reflect the difference between the estimated sales price and carrying value.

Subsequent to the merger, Generation discovered that, for the first two weeks following merger close, due to a software error Generation inadvertently bid certain generating units into the PJM energy market at prices that slightly exceeded the cost-based caps to which it had agreed. This error was a violation of the commitments made in connection with merger approvals by DOJ, FERC and the MDPSC. Generation reported the error to the DOJ, FERC and the MDPSC and committed to remedy the impacts of its error. The MDPSC held a hearing to review the error, and accepted Generation's proposed remediation. Subsequent close examination by Generation of its cost-based bids also revealed the need for some minor adjustments to the cost build up for certain of its PJM units. Generation is coordinating with PJM to determine the impact on Generation's revenues and the market from this error and these adjustments, and Generation will work with PJM to reverse the financial impacts. Generation cannot predict what final action DOJ, FERC or the MDPSC might take in connection with this error and these adjustments.

In addition, in January 2012, Exelon and Constellation reached an agreement with EDF under which EDF withdrew its opposition to the Exelon-Constellation merger. The terms of the agreement address CENG, a joint venture between Constellation and EDF that owns and operates a total of three nuclear facilities with a total of five generating units in Maryland and New York. The agreement reaffirms the terms of the joint venture. The agreement did not include any exchange of monetary consideration, and Exelon does not expect the agreement will have a material effect on Exelon's and Generation's future results of operations, financial position and cash flows.

Exelon was named in suits filed in the Circuit Court of Baltimore City, Maryland alleging that individual directors of Constellation breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors' breaches. Similar suits were also filed in the United States District Court for the District of Maryland. The suits sought to enjoin a Constellation shareholder vote on the proposed merger until all material information was disclosed and sought rescission of the proposed merger. During the third quarter of 2011, the parties to the suits reached an agreement in principle to settle the suits through additional disclosures to Constellation shareholders. On June 26, 2012, the court approved the settlement and entered final judgment.

Accounting for the Merger Transaction

The total consideration in the merger was based on the opening price of a share of Exelon common stock on March 12, 2012 (in millions):

	Number of Shares/ Awards Issued	Total Fair Value
Issuance of Exelon common stock to Constellation shareholders and equity award holders at the exchange ratio of 0.930 shares for each share of Constellation common stock; based on the opening price of Exelon common stock on March 12, 2012 of $38.91(a)	187.45	$ 7,294
Issuance of Exelon equity awards to replace existing Constellation equity awards(b)	11.30	71
Total purchase price		$ 7,365

(a) The number of shares issued excludes 0.7 million shares of stock that are held in a custodian account specifically for the settlement of unvested share-based restricted stock awards. The related share value is excluded from the estimated fair value as these awards have not vested and therefore are not in the purchase price.

(b) Includes vested Constellation stock options and restricted stock units converted at fair value to Exelon awards on March 12, 2012. The fair value of the stock options was determined using the Black-Scholes model.

All options to purchase Constellation common stock under various equity agreements were converted into options to acquire a number of shares of Exelon common stock (as adjusted for the exchange ratio) at an option price. All Constellation unvested restricted stock awards granted prior to April 28, 2011, that were outstanding immediately prior to the consummation of the Merger, became vested on a pro rata basis (determined based upon the number of months from the start of the applicable restricted period to the closing of the Initial Merger) and converted into Exelon common stock at the exchange ratio in accordance with the applicable stock plan and award agreement terms. All Constellation restricted stock awards that remained unvested on a pro rata basis pursuant to the foregoing formula, and any Constellation unvested restricted stock awards granted after April 28, 2011, have been assumed by Exelon and automatically converted into shares of unvested restricted stock of Exelon at the exchange ratio. Likewise, all restricted stock units granted prior to April 28, 2011 under the Constellation Plans and outstanding immediately prior to the completion of the Initial Merger became vested on a pro rata basis (determined based upon the number of months from the start of the applicable restricted period to the closing of the Initial Merger) and have been assumed by Exelon and automatically converted into a number of shares of Exelon common stock at the exchange ratio.

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 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 4 — 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 to assess the fair values of certain assets acquired and liabilities assumed were considered preliminary as a result of the short time period between the closing of the merger and the end of the first quarter of 2012. The allocation of the purchase price may be modified up to one year from the date of the merger as more information is obtained about the fair value of assets acquired and liabilities assumed; however, Exelon expects to finalize these amounts by the end of 2012, if not sooner. The preliminary valuations performed in the first quarter of 2012 were updated in the second quarter of 2012, with the most significant adjustments to the preliminary valuation amounts made to the fair values assigned to the acquired power supply contracts and fuel contracts, unregulated property, plant and equipment and investments in affiliates. The preliminary amounts recognized are subject to further revision until the valuations are completed and to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date. Any changes to the fair value assessments may affect the purchase price allocation and material changes could require the financial statements to be retroactively amended.

The updated preliminary purchase price allocation of the Initial Merger of Exelon with Constellation and Exelon's contribution of certain subsidiaries of Constellation to Generation at June 30, 2012 was as follows:

Preliminary Purchase Price Allocation	Exelon	Generation
Current assets	$ 4,944	$ 3,649
Property, plant and equipment	9,249	3,930
Unamortized energy contracts	3,171	3,171
Other intangibles, trade name and retail relationships	472	472
Investment in affiliates	1,942	1,942
Pension and OPEB regulatory asset	740	—
Other assets	2,644	1,266
Total assets	23,162	14,430
Current liabilities	3,409	2,798
Unamortized energy contracts	1,718	1,512
Long-term debt, including current maturities	6,038	2,972
Noncontrolling interest	95	95
Deferred credits and other liabilities and preferred securities	4,537	1,781
Total liabilities, preferred securities and noncontrolling interest	15,797	9,158
Total purchase price	$ 7,365	$ 5,272

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 valuation of the acquired intangible assets and liabilities was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power and fuel prices and the discount rate. 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 its Consolidated Balance Sheets the unamortized energy contract assets and liabilities for these contracts. The weighted-average amortization period is approximately 1.5 years.

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

The fair value of the Constellation trade name intangible asset was determined based on the relief from royalty method of the income approach whereby fair value is the present value of the license fees avoided by owning the assets. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the hypothetical royalty rate and the discount rate. The intangible assets are amortized on a straight line basis over an estimated 10 year useful life as amortization expense. The trade name intangible asset is included in deferred debits and other assets within Exelon's and Generation's Consolidated Balance Sheets.

The fair value of the retail relationships was determined based on a "multi-period excess method" of the income approach. Under this method, the intangible asset's fair value is equal to the estimated future cash flows that will be earned on the current customer base, taking into account expected contract renewals based on customer attrition rates and costs to retain those customers. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the customer attrition rate and the discount rate. The intangible assets are amortized on a straight line basis over the useful life of the underlying assets averaging approximately 12 years as amortization expense. 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, 2012:

					Estimated amortization expense				
Description	Weighted Average Amortization	Gross	Accumulated Amortization	Net	Remainder of 2012	2013	2014	2015	2016
Unamortized energy contracts, net(a)	1.5	$1,453	$ (489)	$ 964	$ 481	$382	$ 70	$15	$(33)
Trade name	10.0	243	(8)	235	17	24	24	24	24
Retail relationships	11.8	229	(7)	222	15	23	22	21	21
Total, net		$1,925	$ (504)	$1,421	$ 513	$429	$116	$60	$ 12

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

Impact of Merger

It is impracticable to determine the current quarter and year-to-date overall financial statement impact for the Constellation subsidiaries contributed down to Generation following the Upstream Merger. 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.

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

The impact of BGE on Exelon's Consolidated Statement of Operations and Comprehensive Income includes operating revenues of $616 million and net income of $16 million during 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, 2012, Exelon, Generation, PECO and BGE incurred merger and integration-related costs of $111 million, $94 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 $584 million, $204 million, $2 million, $11 million and $154 million, respectively. These costs are classified primarily within Operating and Maintenance Expense in the Registrants' respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the $113 million BGE customer rate credit, which is included as a reduction to operating revenues for the six months ended June 30, 2012.

Severance Costs

The Registrants have an ongoing severance plan under which, in general, the longer a terminated 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 its 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. Exelon recorded a pre-tax charge for estimated salary continuance, health and welfare severance benefits, and other benefits costs of $83 million in March 2012 as a result of the planned job reductions. During the three months ended June 30, 2012, Exelon identified specific employees to be severed pursuant to a merger-related staffing and selection process. As a result, Exelon recorded an additional pre-tax charge of $36 million to reflect the estimated severance costs associated with the specifically identified employees. The estimated amount of severance costs associated with the post-merger integration, including those costs to be incurred after June 30, 2012, for Exelon is $121 million, which includes $72 million, $16 million, $7 million and $18 million for Generation, ComEd, PECO and BGE, respectively. In addition, certain employees identified during the staffing and selection process also receive pension and other postretirement benefits that are deemed contractual termination benefits. See Note 12 — Retirement Benefits for additional information on the contractual termination benefits.

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:

Severance Benefits(a)	Exelon	Generation	ComEd(b)	PECO	BGE(c)
Expense recorded — three months	$ 36	$ 25	$ 5	$ 2	$ 2
Expense recorded — six months	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 $16 million, as of June 30, 2012, for severance benefits costs. The majority of these costs are expected to be recovered over a five-year period.
(c) Consistent with MDPSC precedent, BGE established a regulatory asset of $18 million, as of June 30, 2012, for severance benefits costs. The majority of these costs are expected to be recovered over a five-year period.

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

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:

Three Months Ended June 30, 2012 Severance liability	Exelon	Generation	ComEd	PECO	BGE
Balance at March 31, 2012	$ 83	$ 16	$ —	$ —	$ 10
Severance charges(a)	40	12	2	—	1
Stock compensation	(5)	1	—	—	—
One-time termination benefits(b)	2	—	—	—	—
Other charges(c)	(1)	1	—	—	1
Payments	(1)	—	—	—	—
Balance at June 30, 2012	$ 118	$ 30	$ 2	$ —	$ 12

Six Months Ended June 30, 2012 Severance liability	Exelon	Generation	ComEd	PECO	BGE
Balance at December 31, 2011	$ —	$ —	$ —	$ —	$—
Severance charges(a)	107	27	2	—	11
Stock compensation	3	1	—	—	—
One-time termination benefits(b)	2	—	—	—	—
Other charges(c)	7	2	—	—	1
Payments	(1)	—	—	—	—
Balance at June 30, 2012	$ 118	$ 30	$ 2	$ —	$ 12

(a) Includes salary continuance and health and welfare severance benefits. Amounts represent ongoing severance plan benefits.
(b) One-time termination benefits began to be recognized in the second quarter of 2012.
(c) Primarily includes life insurance, employer payroll taxes, educational assistance, and outplacement services.

Cash payments under the plan began in the second quarter of 2012 and will continue through 2016. Substantially all cash payments under the plan are expected to be made by the end of 2016 resulting in the completion of the merger restructuring plan.

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.

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

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.

	Generation Three Months Ended June 30,		Exelon Three Months Ended June 30,	
	2012	2011(a)	2012	2011(b)
Total Revenues	$ 4,051	$ 4,782	$ 6,256	$ 7,425
Net income attributable to Exelon	397	221	528	401
Basic Earnings Per Share	n.a.	n.a.	$ 0.62	$ 0.47
Diluted Earnings Per Share	n.a.	n.a.	0.62	0.47

	Generation Six Months Ended June 30,		Exelon Six Months Ended June 30,	
	2012	2011(a)	2012	2011(b)
Total Revenues	$ 8,523	$ 9,789	$13,284	$15,493
Net income attributable to Exelon	567	442	979	644
Basic Earnings Per Share	n.a.	n.a.	$ 1.26	$ 0.76
Diluted Earnings Per Share	n.a.	n.a.	1.25	0.76

(a) The amounts above include non-recurring costs directly related to the merger of $94 million and $204 million for the three and six months ended June 30, 2011, respectively.
(b) The amounts above include non-recurring costs directly related to the merger of $111 million and $584 million for the three and six months ended June 30, 2011, respectively.

Other Acquisitions (Exelon and Generation)

Antelope Valley Solar Ranch One. On September 30, 2011, Generation acquired all of the interests in Antelope Valley Solar Ranch One (Antelope Valley), a 230-MW solar PV project under development in northern Los Angeles County, California, from First Solar, Inc., which developed and will build, operate and maintain the project. On April 5, 2012, Antelope Valley received the first DOE-guaranteed loan advance of $69 million and terminated the put option that Generation had on the Antelope Valley project. See Note 9 - Debt and Credit Agreements for additional information.

Wind Development. As part of its plan to construct multiple wind facilities in 2012, Generation has acquired several project entities. The acquisitions are not considered material individually or in the aggregate for disclosure.

4. 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 2 of the Exelon 2011 Form 10-K and Note 6 of Constellation's and BGE's 2011 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).

Background

EIMA provides a structure for substantial capital investment over a ten-year period to modernize Illinois' electric utility infrastructure. EIMA allows the recovery of costs by a utility through a pre-established performance-based formula rate tariff, approved by the ICC and will provide greater certainty as to the recovery of those costs. ComEd made an initial contribution of $15 million (recognized as expense in 2011) to a new Science and Technology Innovation Trust fund on July 31, 2012, and will make recurring annual contributions of $4 million beginning in 2012, which will be used for customer education for as long as the AMI Deployment Plan remains in effect. In addition, ComEd will contribute $10 million per year for five years, as long as ComEd is subject to EIMA, to fund customer assistance programs for low-income customers, which amounts will not be recoverable through rates.

Capital Investment

On January 6, 2012, ComEd filed its Infrastructure Investment Plan with the ICC. Under that plan, ComEd will invest approximately $2.6 billion over ten years to modernize and storm-harden its distribution system and to implement smart grid technology. These investments will be incremental to ComEd's historical level of capital expenditures. The ICC filing specifically included ComEd's $233 million investment plan for 2012. On April 23, 2012, ComEd filed its initial AMI Deployment Plan with the ICC. On June 22, 2012, the ICC approved the AMI Deployment Plan with certain modifications. Implementation of the investment plan began in early 2012 while smart meter installation in homes and businesses is expected to begin later in 2012, but is subject to the rehearing below.

Formula Rate Tariff

On November 8, 2011, ComEd filed its initial formula rate tariff and associated testimony based on 2010 costs and 2011 plant additions. The primary purpose of that proceeding was to establish the formula rate under which rates will be calculated going-forward, and the initial rates, which went into effect in late June. On May 30, 2012, the ICC issued its final Order (Order) in that proceeding. The Order reduced the annual revenue requirement by $168 million, or approximately $110 million more than proposed by ComEd. Of this incremental revenue requirement reduction, approximately $50 million reflected the ICC's determination that certain costs should be recovered through alternative rate recovery tariffs available to ComEd or will be reflected in the annual reconciliation, thereby primarily delaying the timing of cash flows. The incremental revenue reduction also reflected a $35 million reduction for the disallowance of return on ComEd's pension asset, a $10 million reduction for incentive compensation related adjustments, and $15 million of reductions for various adjustments for cash working capital, operating reserves, and other technical items. In the second quarter of 2012, ComEd recorded a reduction of revenue of approximately $100 million pre-tax to decrease the regulatory asset for the 2011 periods and for the first three months of 2012 consistent with the terms of the Order. On June 5, 2012, ComEd filed its application for rehearing with the ICC. On June 22, 2012 the ICC granted expedited rehearing on ComEd's pension asset recovery, the use of average or year-end rate base in determining ComEd's reconciliation revenue requirement and the interest rate charged on over/under recovered costs. The expected schedule for the rehearing allows for a decision by September 19, 2012. As a further result of the Order, on July 6, 2012, ComEd filed for rehearing of the AMI Deployment Plan to amend the timing and amount of the capital investment under that plan. On July 11, 2012, the ICC granted rehearing on ComEd's AMI Deployment Plan. A final order on rehearing is due by December 7, 2012.

Annual Reconciliation

ComEd will file an annual reconciliation of the revenue requirement in effect in a given year to reflect actual costs that the ICC determines are prudently and reasonably incurred for such year. ComEd made its initial 2011 reconciliation filing on April 30, 2012, which reconciled the 2011 revenue requirement in effect to ComEd's actual 2011 costs incurred (the rates will take effect in January 2013). ComEd updated its 2011 reconciliation filing on June 12, 2012 to reflect the impacts of the Order discussed above. A similar reconciliation with respect to 2012 will be filed in second quarter 2013 with any adjustments to rates taking effect in January 2014. As of June 30, 2012 and December 31, 2011, ComEd recorded an estimated net regulatory asset of $26 million and $84 million, respectively, which represents the ICC's approved distribution formula and associated rulings as of June 30, 2012 and ComEd's best estimate of the probable increase in distribution rates expected to be approved by the ICC to provide for recovery of prudent and reasonable costs incurred for the twelve months ended December 31, 2011 and for the six months ended June 30, 2012. The evidentiary hearing in ComEd's 2011 reconciliation rate case is expected to begin on September 25, 2012, with a final order due by December 26, 2012.

Appeal of 2007 Illinois Electric Distribution Rate Case (Exelon and ComEd). The ICC issued an order in ComEd's 2007 electric distribution rate case (2007 Rate Case) approving a $274 million increase in ComEd's annual delivery services revenue requirement, which became effective in September 2008. In the order, the ICC authorized a 10.3% rate of return on common equity. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). The Court issued a decision on September 30, 2010, ruling against ComEd on the treatment of post-test year accumulated depreciation and the recovery of system modernization costs via a rider (Rider SMP). The ICC subsequently initiated a proceeding on remand. On February 23, 2012, the ICC issued an order in the remand proceeding requiring ComEd to provide a refund of approximately $37 million to customers related to the treatment of post-test year accumulated depreciation issue. On March 26, 2012, ComEd filed a notice of appeal. ComEd has recognized for accounting purposes its best estimate of any refund obligation.

Advanced Metering Program Proceeding (Exelon and ComEd). In October 2009, the ICC approved a modified version of Rider SMP (Rider AMP). ComEd collected approximately $24 million under Rider AMP through December 31, 2011. Several other parties, including the Illinois Attorney General, appealed the ICC's order on Rider AMP. In ComEd's 2010 electric distribution rate case, the ICC approved ComEd's transfer of other costs from recovery under Rider AMP to recovery through base electric distribution rates. On March 19, 2012, the Court reversed Rider AMP, concluding that the ICC's October 2009 approval of the rider constituted single-issue ratemaking. ComEd filed a Petition for Leave to Appeal to the Illinois Supreme Court on April 23, 2012. ComEd believes any refund obligation associated with Rider AMP should be prospective from no earlier than the date of the Court's order on March 19, 2012, which would have an immaterial impact at ComEd and Exelon.

Illinois Procurement Proceedings (Exelon, Generation and ComEd). ComEd is permitted to recover its electricity procurement costs from its retail customers without mark-up. Since June 2009, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. In order to fulfill a requirement of the Illinois Settlement Legislation, ComEd hedged the price of a significant portion of energy purchased in the spot market with a five-year variable-to-fixed financial swap contract with Generation that expires on May 31, 2013. EIMA contains a provision for the IPA to conduct procurement events for energy and REC requirements for the June 2013 through December 2017 period. The procurement events mandated under EIMA were completed during February 2012. See Note 16 — Commitments and Contingencies for additional information on ComEd's energy commitments.

Pennsylvania Regulatory Matters

Pennsylvania Procurement Proceedings (Exelon and PECO). PECO's PAPUC-approved DSP Program, under which PECO is providing default electric service, has a 29-month term that began January 1, 2011 and ends May 31, 2013. Under the DSP Program, PECO is permitted to recover its electric procurement costs from retail default service customers without mark-up through the GSA. The GSA provides for the recovery of energy, capacity, ancillary costs and administrative costs and is subject to adjustments at least quarterly for any over or under collections. The filing and implementation costs of the DSP Program were recorded as a regulatory asset and are being recovered through the GSA over its 29-month term. In January and April 2012, PECO entered into contracts with PAPUC-approved bidders, including Generation, for electric supply for default electric service which included full requirements fixed price contracts for its residential, small commercial and medium commercial procurement classes that commenced in June 2012, hourly spot market price full requirements contracts for its small and medium commercial and large commercial and industrial procurement classes that commenced in June 2012 and block contracts for its residential class beginning in December 2012. 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. PECO has one competitive procurement remaining over the term of this DSP Program.

On January 13, 2012, PECO filed its second DSP Plan for approval with the PAPUC. The plan outlined how PECO will purchase electricity for default customers from June 1, 2013 through May 31, 2015. To continue to ensure a competitive procurement process for residential customers, PECO proposed to procure electricity through a combination of one-year and two-year full requirements fixed price contracts, reduce the amount of time between when the energy is procured and when it is provided to customers and complete an annual, rather than quarterly, reconciliation of costs for actual versus forecasted energy use. The DSP Plan also proposed to eliminate the AEPS rider and recover AEPS costs through the GSA. Hearings on the filing concluded on May 22, 2012 and a PAPUC ruling is expected in mid-October 2012.

Smart Meter and Smart Grid Investments (Exelon and PECO). In April 2010, the PAPUC approved PECO's $550 million Smart Meter Procurement and Installation Plan under which PECO will install more than 1.6 million smart meters and deploy advanced communication networks by 2020. In 2010, PECO entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA of 2009. Under the SGIG, PECO was awarded $200 million, the maximum grant allowable under the program, for its SGIG project — Smart Future Greater Philadelphia. Through 2020, PECO plans to spend up to $650 million on its smart grid and smart meter infrastructure. The $200 million SGIG is being used to reduce the impact of these investments on PECO ratepayers.

As of June 30, 2012, PECO received $119 million in reimbursements from the DOE. PECO's outstanding receivable from the DOE for reimbursable costs was $14 million as of June 30, 2012, which has been recorded in other accounts receivable, net on Exelon's and PECO's Consolidated Balance Sheets.

Energy Efficiency Program (Exelon and PECO). On August 2, 2012, the PAPUC issued a final order regarding the next phase (Phase 2) of the EE&C Program. The final order provides details on the design and implementation of Phase 2, which will go into effect on June 1, 2013. The order tentatively establishes PECO's three year cumulative consumption reduction target of 2.9%. The order also provides the opportunity for any electric utility to challenge its proposed target in an evidentiary hearing. PECO is evaluating these new requirements prior to filing its Phase 2 plan.

Natural Gas Choice Supplier Tariff (Exelon and PECO). During 2011, the PAPUC approved PECO's tariff supplements to its Gas Choice Supplier Coordination Tariff and its Retail Gas Service Tariff to address the new licensing requirements for natural gas suppliers (NGS) set forth in the PAPUC's final rulemaking order, which became effective January 1, 2011. The new licensing requirements broaden the types of collateral that PECO can require to mitigate its risk related to a NGS default, as well as PECO's ability to adjust collateral when material changes in supplier creditworthiness occur. PECO has completed its creditworthiness determinations and notified affected NGSs of their new collateral levels. As a result, PECO has obtained $14 million of collateral.

Investigation of PA 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 January 13, 2012, PECO filed its second DSP for approval with the PAPUC, which proposed 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. On March 1, 2012, the PAPUC issued the final order describing more detailed recommendations to be implemented prior to an expiration of the electric distribution company's current default service plan and providing guidelines for electric distribution companies for the development of their next default service plan.

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 in future test years. On August 2, 2012, the PAPUC issued a final order establishing rules and procedures to implement the ratemaking provisions of Act 11.

Maryland Regulatory Matters

2011 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated electric and gas distribution rate order issued in December 2010. As part of the March 2011 comprehensive rate order, BGE was authorized to defer $19 million of costs as regulatory assets. These costs will be recovered over a 5-year period beginning December 2010 and include the deferral of $16 million of storm costs incurred in February 2010. The regulatory asset for the storm costs earns a regulated rate of return.

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE which 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. Under a grant from the DOE, BGE is a recipient of $200 million in federal funding for its smart grid and other related initiatives, which substantially reduces the total cost of these initiatives. The project to install the smart meters began in late April 2012.

As of June 30, 2012, BGE had received $114 million in reimbursements from the DOE. As of June 30, 2012, BGE's outstanding receivable from the DOE for reimbursable costs was $9 million, which has been recorded in other accounts receivable, net on Exelon's and BGE's Consolidated Balance Sheets.

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

New Electric Generation (Exelon 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 a 700 MW natural gas-fired combined-cycle generation plant in Waldorf, Maryland, with an assumed commercial operation date of June 1, 2015. The initial term of the proposed contract is 20 years. The CfD will provide that the utilities will pay (or receive) the difference between CPV's contract prices and the revenues CPV receives for capacity and energy from bidding the unit into the PJM markets. The three Maryland utilities are required to enter into a CfD in amounts proportionate to their relative SOS load as of the date of execution. Pursuant to the MDPSC's Order, between the period of April 12, 2012 and July 6, 2012, the utilities met with CPV and the consultant for the MDPSC, Boston Pacific Company, Inc. (Boston Pacific), to negotiate changes to the CfD for submission to the MDPSC for approval. On July 10, 2012, Boston Pacific filed a revised version of the CfD with the MDPSC, along with a memorandum detailing the parties' negotiations and the changes included in the revised CfD. BGE, the two other Maryland utilities, and other interested parties have filed written comments on the revised CfD proposed by Boston Pacific and have provided further comments at a hearing held July 31, 2012. Depending on the precise terms of the CfD, the eventual market conditions, and the manner of cost recovery, the CfD could have a material impact on Exelon's and BGE's results of operations, cash flows and financial positions. 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 remain 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, where similar appeals have been filed by other interested parties. The two other Maryland utilities also filed petitions for judicial review in other Maryland state courts, which are also expected to be transferred to the Circuit Court for Baltimore City. Once transferred, it is likely that the cases will be consolidated and heard together.

2012 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 27, 2012, BGE filed an application for increases of $151 million and $53 million to its electric and gas base rates, respectively, with the MDPSC. The requested rate of return on equity in the application is 10.5%. The new electric and gas distribution base rates are expected to take effect in late February 2013. BGE cannot predict how much of the requested increases, if any, the MDPSC will approve.

Federal Regulatory Matters

PJM Minimum Offer Price Rule (Exelon and Generation). PJM's capacity market rules include a Minimum Offer Price Rule (MOPR) intended to ensure that a competitive capacity offer is based on the costs and competitive market revenues of a new entry unit. On February 1, 2011, in response to the enactment of New Jersey Senate Bill 2381, Exelon Generation joined the PJM Power Providers Group (P3) complaint at FERC seeking a revision to PJM's MOPR to preclude the exercise of buyer market power. In response to P3's complaint, PJM filed revisions to the MOPR which were largely approved by FERC in its April 12, 2011 Order. The revised MOPR, among other things, sets a minimum price level for sell offers for capacity from certain types of new generation resources submitted in PJM's capacity market auctions. While a number of state regulators and consumer groups opposed the MOPR revision, the changes were in line with recent FERC orders regarding capacity markets in the New York and New England ISOs. A number of parties filed for rehearing of the FERC order.

In May 2012, PJM announced the results of its capacity auction covering 2015/2016. Several new units with state-sanctioned subsidy contracts cleared in the auction at prices below the MOPR. There is potential that states will expand such state-sanctioned subsidy programs or that other states may seek to establish similar programs. Exelon believes that further revisions to the MOPR may be necessary to ensure that the potential to artificially reduce capacity auction prices is appropriately limited in PJM.

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

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

Exelon, ComEd, PECO and BGE 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, 2012 and December 31, 2011. Upon consummation of the merger, the Registrants reclassified certain regulatory asset and liability balances as of December 31, 2011 in order to align the reporting of the regulated utilities. For additional information on the specific regulatory assets and liabilities, refer to Note 2 of the Exelon 2011 Form 10-K for Exelon, ComEd and PECO and Note 6 of BGE's 2011 Form 10-K.

June 30, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits(a)	$ 262	$ 3,476	$ —	$ —	$ 3	$ —	$ 2	$ —
Deferred income taxes	12	1,244	5	62	—	1,118	7	64
AMI and smart meter programs	2	50	2	5	—	24	—	21
Under-recovered distribution service costs	—	54	—	54	—	—	—	—
Debt costs	14	75	11	68	3	7	2	9
Fair value of BGE long-term debt(b)	48	232	—	—	—	—	—	—
Fair value of BGE supply contract(c)	110	51	—	—	—	—	—	—
Severance	29	42	25	25	—	—	4	17
Asset retirement obligations	—	77	—	53	—	24	—	—
MGP remediation costs	48	236	41	205	6	29	1	2
RTO start-up costs	3	3	3	3	—	—	—	—
Under-recovered electric universal service fund costs	9	—	—	—	9	—	—	—
Financial swap with Generation	—	—	506	—	—	—	—	—
Renewable energy and associated RECs	19	92	19	92	—	—	—	—
Under-recovered energy and transmission costs	151	—	101	—	10(d)	—	40	—
DSP Program costs	2	2	—	—	2	2	—	—
Deferred storm costs	3	8	—	—	—	—	3	8
Electric generation-related regulatory asset	16	48	—	—	—	—	16	48
Rate stabilization deferral	65	269	—	—	—	—	65	269
Energy efficiency and demand response programs	39	108	—	—	—	—	39	108
Other	35	36	13	16	21	12	—	4
Total regulatory assets	$ 867	6,103	$ 726	$ 583	$ 54	$ 1,216	$ 179	$ 550

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

June 30, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Nuclear decommissioning	$ —	$ 2,352	$ —	$ 1,960	$ —	$ 392	$ —	$ —
Removal costs	87	1,397	65	1,189	—	—	22	208
Energy efficiency and demand response programs	31	72	19	—	12	72	—	—
Electric distribution tax repairs	19	142	—	—	19	142	—	—
Over-recovered distribution service costs	28	—	28	—	—	—	—	—
Over-recovered uncollectible accounts	27	—	27	—	—	—	—	—
Over-recovered energy and transmission costs	60	—	7	—	53(e)	—	—	—
Over-recovered gas universal service fund costs	3	—	—	—	3	—	—	—
Over-recovered AEPS costs	4	—	—	—	4	—	—	—
Total regulatory liabilities	$ 259	$ 3,963	$ 146	$ 3,149	$ 91	$ 606	$ 22	$ 208

December 31, 2011	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits	$ 204	$ 2,794	$ —	$ —	$ 7	$ —	$ 3	$ —
Deferred income taxes	5	1,176	5	66	—	1,110	7	64
AMI and smart meter programs	2	28	2	6	—	22	—	15
Under-recovered distribution service costs	14	70	14	70	—	—	—	—
Debt costs	18	81	15	73	3	8	2	10
Severance	25	38	25	38	—	—	—	1
Asset retirement obligations	—	74	—	50	—	24	—	—
MGP remediation costs	30	129	24	91	6	38	1	2
RTO start-up costs	3	4	3	4	—	—	—	—
Under-recovered electric universal service fund costs	3	—	—	—	3	—	—	—
Financial swap with Generation	—	—	503	191	—	—	—	—
Renewable energy and associated RECs	9	97	9	97	—	—	—	—
Under-recovered energy and transmission costs	57	—	48	—	9(d)	—	50	—
DSP Program costs	3	2	—	—	3	2	—	—
Deferred storm costs	—	—	—	—	—	—	3	9
Electric generation-related regulatory asset	—	—	—	—	—	—	16	56
Rate stabilization deferral	—	—	—	—	—	—	63	295
Energy efficiency and demand response programs	—	—	—	—	—	—	29	95
Other	17	25	9	13	8	12	—	3
Total regulatory assets	$ 390	$ 4,518	$ 657	$ 699	$ 39	$ 1,216	$ 174	$ 550

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

December 31, 2011	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Nuclear decommissioning	$ —	$ 2,222	$ —	$ 1,857	$ —	$ 365	$ —	$ —
Removal costs	61	1,185	61	1,185	—	—	18	200
Energy efficiency and demand response programs	49	69	49	—	—	69	—	—
Electric distribution tax repairs	19	151	—	—	19	151	—	—
Over-recovered uncollectible accounts	15	—	15	—	—	—	—	—
Over-recovered energy and transmission costs	42	—	12	—	30(e)	—	—	—
Over-recovered gas universal service fund costs	3	—	—	—	3	—	—	—
Over-recovered AEPS costs	8	—	—	—	8	—	—	—
Total regulatory liabilities	$ 197	$ 3,627	$ 137	$ 3,042	$ 60	$ 585	$ 18	$ 200

(a) As of June 30, 2012, pension and other postretirement benefit regulatory assets include a regulatory asset established at the date of the merger related to the recognition of BGE's share of the underfunded status of the defined benefit postretirement plan as a liability on Exelon's Consolidated Balance Sheets. The regulatory asset is being amortized in accordance with the authoritative guidance for pensions and postretirement benefits over a period of approximately 12 years. BGE is currently recovering these costs through base rates. BGE is not earning a return on the recovery of these costs in base rates.
(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.
(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.
(d) Relates to the under-recovered transmission costs.
(e) Includes $12 million and $5 million related to the over-recovered natural gas costs under the PGC and $41 million and $25 million related to the over-recovered electric supply costs under the GSA as of June 30, 2012 and December 31, 2011, respectively.

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. Purchased 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, 2012 and December 31, 2011.

As of June 30, 2012	Exelon	ComEd	PECO	BGE
Purchased receivables(a)	$ 156	$ 29	$ 63	$ 64
Allowance for uncollectible accounts(b)	(11)	(2)	(5)	(4)
Purchased receivables, net	$ 145	$ 27	$ 58	$ 60

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

As of December 31, 2011	Exelon	ComEd	PECO	BGE
Purchased receivables(a)	$ 68	$ 16	$ 52	$ 61
Allowance for uncollectible accounts(b)	(5)	—	(5)	(3)
Purchased receivables, net	$ 63	$ 16	$ 47	$ 58

(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.

5. 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, 2012	For the Period March 12, through June 30, 2012
CENG	$ 4	$ (5)
Amortization of basis difference in CENG	(62)	(74)
Total equity investment income (loss) — CENG	$ (58)	$ (79)

As of March 12, 2012, Generation had an initial basis difference of approximately $198 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 impact the earnings of CENG.

In future periods, Generation may be eligible for distributions from CENG in excess of its 50.01% ownership interest based on tax sharing provisions contained in the operating agreement for CENG. Generation would record these distributions, if realized, in earnings in the period earned.

Related Party Transactions (Exelon and Generation)

CENG

Generation has an agreement with CENG under which it is purchasing 85-90% 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, a subsidiary of Generation has a power services agency agreement (PSAA) with CENG. The PSAA is a five-year agreement under which Generation provides scheduling, asset management and billing services to CENG for a specified monthly fee. The charges for services reflect the cost of the service, with such cost not to exceed approximately $358,000 per month.

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

In addition to the PSAA, Exelon has an administrative services agreement (ASA) with CENG, which expires in 2017. Under the ASA, BSC provides a variety of support services to CENG. The ASA includes both a consumption-based pricing structure and a fixed-price structure which are subject to change in future years based on the level of service needed. Pursuant to an agreement between Exelon and EDF, the pricing in the ASA is in the process of being amended so that the charges for services reflect actual costs determined on the same basis that BSC charges its affiliates for similar services.

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

Agreement	Increase/(Decrease) in Earnings Three Months Ended June 30, 2012	Increase/(Decrease) in Earnings 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(a)	3	4	Operating revenues	—
ASA	12	15	Operating expenses	4

(a) Includes $2 million of amortization related to the intangible contract liability established in purchase accounting.

In May 2011, CENG issued an unsecured revolving promissory note to borrow up to an aggregate principal amount of $62.5 million from a subsidiary of Generation. CENG also issued a promissory note to EDF on substantially identical terms, such that any request for borrowings by CENG must be submitted 50.01% to Generation and 49.99% to EDF.

Interest accrues on the amounts borrowed on a daily basis at a rate of LIBOR, plus 250 basis points. Amounts are due at the earlier of October 31, 2012 or the date upon which the note is accelerated in accordance with the terms of the agreement.

As of June 30, 2012, CENG had borrowed $55 million from Generation.

6. 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, such as a significant negative regulatory outcome, that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount. In May 2012, the ICC issued a final Order (Order) in ComEd's 2011 formula rate proceeding under the EIMA that reduced ComEd's annual revenue requirement being recovered in current rates by $168 million. See Note 4 — Regulatory Matters for further detail. Management concluded that the Order represents an event that required an interim goodwill impairment assessment and, as a result, ComEd tested its goodwill for impairment as of May 31, 2012.

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 the annual impairment test, 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. In performing the discounted cash flow analysis for the interim goodwill test, management assumed that ComEd would ultimately prevail in appealing certain aspects of the Order, specifically the return on ComEd's pension asset and the use of year-end rate base in determining ComEd's annual revenue requirement being recovered in current rates. The disallowances related to the pension asset return and year-end rate base are estimated to reduce ComEd's revenue requirement recovered in rates by approximately $75 – $130 million annually. The assessment also reflects several favorable changes in certain market assumptions since the annual impairment assessment in 2011, including the weighted average cost of capital and market multiples.

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

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.

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

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation and preferred securities as of June 30, 2012 and December 31, 2011:

Exelon

	June 30, 2012				December 31, 2011	
	Carrying Amount	Fair Value Level 1	Fair Value Level 2	Fair Value Level 3	Carrying Amount	Fair Value
Short-term liabilities	$ 605	$ 4	$ 601	$ —	$ 737	$ 737
Long-term debt (including amounts due within one year)	18,115	—	19,554	113	12,627	14,488
Long-term debt to financing trusts	649	—	653	—	390	358
SNF obligation	1,019	—	839	—	1,019	886
Preferred securities of subsidiary	87	—	82	—	87	79

Generation

	June 30, 2012				December 31, 2011	
	Carrying Amount	Fair Value Level 1	Fair Value Level 2	Fair Value Level 3	Carrying Amount	Fair Value
Short-term liabilities	$ 10	$ —	$ 10	$ —	$ 2	$ 2
Long-term debt (including amounts due within one year)	7,369	—	7,451	95	3,677	4,231
SNF obligation	1,019	—	839	—	1,019	886

ComEd

	June 30, 2012				December 31, 2011	
	Carrying Amount	Fair Value Level 1	Fair Value Level 2	Fair Value Level 3	Carrying Amount	Fair Value
Short-term liabilities	$ 178	$ —	$ 178	$ —	$ —	$ —
Long-term debt (including amounts due within one year)	5,216	—	6,174	18	5,665	6,540
Long-term debt to financing trust	206	—	208	—	206	184

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

PECO

	June 30, 2012				December 31, 2011	
	Carrying Amount	Fair Value Level 1	Fair Value Level 2	Fair Value Level 3	Carrying Amount	Fair Value
Short-term liabilities	$ 225	$ —	$ 225	$ —	$ 225	$ 225
Long-term debt (including amounts due within one year)	1,973	—	2,307	—	1,972	2,295
Long-term debt to financing trusts	184	—	180	—	184	174
Preferred securities	87	—	82	—	87	79

BGE

	June 30, 2012				December 31, 2011	
	Carrying Amount	Fair Value Level 1	Fair Value Level 2	Fair Value Level 3	Carrying Amount	Fair Value
Long-term debt (including amounts due within one year)	1,961	—	2,270	—	2,101	2,377
Long-term debt to financing trusts	258	—	264	—	258	256

Short-Term Liabilities. The short-term liabilities included in the table 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 (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 9 — 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 are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the electric utility sector with similar credit ratings in both the primary and secondary market, across the Registrants' debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

The Registrants also have tax-exempt debt. 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 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 in 2020 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 2020.

Preferred Securities of Subsidiary, Long-Term Debt to Financing Trusts and Junior Subordinated Debentures. The fair value of these securities is determined using observable market prices on the last trade date of the quarter as these securities are actively traded, less accrued interest. The securities are registered with the SEC and are public.

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.
- Level 3 — unobservable inputs, such as internally developed pricing models 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 and investments priced using an alternative pricing mechanism.

There were no transfers between Level 1 and Level 2 during the six months ended June 30, 2012.

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

Exelon

The following tables present assets and liabilities measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2012 and December 31, 2011:

As of June 30, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 936	$ —	$ —	$ 936
Nuclear decommissioning trust fund investments				
Cash equivalents	320	—	—	320
Equity				
Equity securities	1,362	—	—	1,362
Commingled funds	—	1,798	—	1,798
Equity funds subtotal	1,362	1,798	—	3,160
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,115	—	—	1,115
Debt securities issued by states of the United States and political subdivisions of the states	—	342	—	342
Debt securities issued by foreign governments	—	73	—	73
Corporate debt securities	—	1,631	—	1,631
Federal agency mortgage-backed securities	—	43	—	43
Commercial mortgage-backed securities (non-agency)	—	39	—	39
Residential mortgage-backed securities (non-agency)	—	12	—	12
Mutual funds	—	8	—	8
Fixed income subtotal	1,115	2,148	—	3,263
Direct lending securities	—	—	54	54
Other debt obligations	—	14	—	14
Nuclear decommissioning trust fund investments subtotal(b)	2,797	3,960	54	6,811
Pledged assets for Zion Station decommissioning				
Equity				
Equity securities	20	—	—	20
Commingled funds	—	18	—	18
Equity funds subtotal	20	18	—	38
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	79	17	—	96
Debt securities issued by states of the United States and political subdivisions of the states	—	60	—	60
Corporate debt securities	—	278	—	278
Federal agency mortgage-backed securities	—	83	—	83
Commercial mortgage-backed securities (non-agency)	—	7	—	7
Commingled funds	—	28	—	28
Fixed income subtotal	79	473	—	552
Direct lending securities	—	—	59	59
Other debt obligations	—	1	—	1
Pledged assets for Zion Station decommissioning subtotal(c)	99	492	59	650

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

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As of June 30, 2012	Level 1	Level 2	Level 3	Total
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds(d)(e)	72	—	—	72
Rabbi trust investments subtotal	74	—	—	74
Commodity mark-to-market derivative assets				
Economic hedges	1,414	5,425	821	7,660
Proprietary trading	2,121	4,720	183	7,024
Effect of netting and allocation of collateral(f)	(3,710)	(8,423)	(261)	(12,394)
Commodity mark-to-market assets subtotal(g)	(175)	1,722	743	2,290
Interest rate mark-to-market derivative assets	—	120	—	120
Other investments	2	—	17	19
Total assets	3,733	6,294	873	10,900
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,807)	(4,194)	(418)	(6,419)
Proprietary trading	(2,171)	(4,500)	(298)	(6,969)
Effect of netting and allocation of collateral(f)	3,978	7,825	268	12,071
Commodity mark-to-market liabilities subtotal(g)(h)	—	(869)	(448)	(1,317)
Interest rate mark-to-market derivative liabilities	—	(89)	—	(89)
Deferred compensation	—	(97)	—	(97)
Total liabilities	—	(1,055)	(448)	(1,503)
Total net assets	$ 3,733	$ 5,239	$ 425	$ 9,397

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 861	$ —	$ —	$ 861
Nuclear decommissioning trust fund investments				
Cash equivalents	562	—	—	562
Equity				
Equity securities	1,275	—	—	1,275
Commingled funds	—	1,822	—	1,822
Equity funds subtotal	1,275	1,822	—	3,097
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,014	33	—	1,047
Debt securities issued by states of the United States and political subdivisions of the states	—	541	—	541
Debt securities issued by foreign governments	—	16	—	16
Corporate debt securities	—	778	—	778
Federal agency mortgage-backed securities	—	357	—	357
Commercial mortgage-backed securities (non-agency)	—	83	—	83
Residential mortgage-backed securities (non-agency)	—	5	—	5
Mutual funds	—	47	—	47
Fixed income subtotal	1,014	1,860	—	2,874
Direct lending securities	—	—	13	13
Other debt obligations	—	18	—	18
Nuclear decommissioning trust fund investments subtotal(b)	2,851	3,700	13	6,564

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

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As of December 31, 2011	Level 1	Level 2	Level 3	Total
Pledged assets for Zion decommissioning				
Equity				
Equity securities	35	—	—	35
Commingled funds	—	30	—	30
Equity funds subtotal	35	30	—	65
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	54	26	—	80
Debt securities issued by states of the United States and political subdivisions of the states	—	65	—	65
Corporate debt securities	—	314	—	314
Federal agency mortgage-backed securities	—	121	—	121
Commercial mortgage-backed securities (non-agency)	—	10	—	10
Commingled funds	—	20	—	20
Fixed income subtotal	54	556	—	610
Direct lending securities	—	—	37	37
Other debt obligations	—	13	—	13
Pledged assets for Zion Station decommissioning subtotal(c)	89	599	37	725
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds(d)(e)	34	—	—	34
Rabbi trust investments subtotal	36	—	—	36
Commodity mark-to-market derivative assets				
Cash flow hedges	—	857	—	857
Economic hedges	—	1,653	124	1,777
Proprietary trading	—	240	48	288
Effect of netting and allocation of collateral(f)	—	(1,827)	(28)	(1,855)
Commodity mark-to-market assets(g)	—	923	144	1,067
Interest rate mark-to-market derivative assets	—	15	—	15
Total assets	3,837	5,237	194	9,268
Liabilities				
Commodity mark-to-market derivative liabilities				
Cash flow hedges	—	(13)	—	(13)
Economic hedges	(1)	(1,137)	(119)	(1,257)
Proprietary trading	—	(236)	(28)	(264)
Effect of netting and allocation of collateral(f)	—	1,295	20	1,315
Commodity mark-to-market liabilities(h)	(1)	(91)	(127)	(219)
Interest rate mark-to-market liabilities	—	(19)	—	(19)
Deferred compensation	—	(73)	—	(73)
Total liabilities	(1)	(183)	(127)	(311)
Total net assets	$3,836	$ 5,054	$ 67	$ 8,957

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

(b) Excludes net assets (liabilities) of $30 million and $(57) million at June 30, 2012 and December 31, 2011, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

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

(c) Excludes net assets of $9 million at December 31, 2011. 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 $57 million related to deferred compensation and $15 million related to Supplemental Executive Retirement Plan. These funds are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.

(e) Excludes $27 million and $25 million of the cash surrender value of life insurance investments at June 30, 2012 and December 31, 2011, respectively.

(f) Includes collateral postings received from counterparties. Collateral received from counterparties, net of collateral paid to counterparties, totaled $268 million, $(598) million and $7 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of June 30, 2012. Collateral received from counterparties, net of collateral paid to counterparties, totaled $532 million and $8 million allocated to Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2011.

(g) The Level 3 balance does not include current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $506 million and $0 million at June 30, 2012 and $503 million and $191 million at December 31, 2011, respectively, 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 $19 million and $92 million at June 30, 2012, respectively, and $9 million and $97 million at December 31, 2011, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

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, 2012 and 2011:

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	—	—	(67)(a)	—	(67)
Included in regulatory assets	—	—	30(b)	—	30
Included in payable for Zion Station decommissioning	—	(1)	—	—	(1)
Change in collateral	—	—	4	—	4
Purchases, sales, issuances and settlements					
Purchases(c)	41	26	—	3	70
Sales	—	(8)	—	—	(8)
Transfers into Level 3	—	—	(34)	—	(34)
Transfers out of Level 3	—	—	3	—	3
Balance as of June 30, 2012	$ 54	$ 59	$ 295	$ 17	$425
The amount of total losses included in income attributed to the change in unrealized losses related to assets and liabilities held for the three months ended June 30, 2012	$ —	$ —	$ (1)	$ —	$ (1)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(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	$ 17	$ —	$ 67
Total realized / unrealized					
Included in net income	—	—	18(a)	—	18
Included in other comprehensive income	—	—	—	—	—
Included in regulatory assets	—	—	(5)(b)	—	(5)
Included in payable for Zion Station decommissioning	—	(1)	—	—	(1)
Change in collateral	—	—	(19)	—	(19)
Purchases, sales, issuances and settlements					
Purchases	41	32	316(c)	17	406
Sales	—	(9)	—	—	(9)
Transfers into Level 3	—	—	(34)	—	(34)
Transfers out of Level 3	—	—	2	—	2
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 six months ended June 30, 2012	$ —	$ —	$ 103	$ —	$103

(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.

(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.

Three Months Ended June 30, 2011	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Total
Balance as of March 31, 2011	$ 31	$ 51	$ 82
Total realized / unrealized gains (losses)			
Included in income	—	21(a)	21
Included in other comprehensive income	—	(3)(b)	(3)
Included in regulatory assets		(85)	(85)
Included in payable for Zion Station decommissioning	3	—	3
Change in collateral	—	2	2
Purchases, sales, issuances and settlements			
Purchases	12	5	17
Sales	(12)	—	(12)
Transfers out of Level 3 — Asset	—	(7)	(7)
Balance as of June 30, 2011	$ 34	$ (16)	$ 18
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, 2011	$ —	$ 30	$ 30

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

Six Months Ended June 30, 2011	Pledged Assets for Zion Decommissioning	Mark-to-Market Derivatives	Total
Balance as of December 31, 2010	$ —	$ 50	$ 50
Total realized / unrealized gains (losses)			
Included in income	—	8(a)	8
Included in other comprehensive income	—	(12)(b)	(12)
Included in regulatory assets	—	(33)	(33)
Included in payable for Zion Station decommissioning	3	—	3
Change in collateral	—	7	7
Purchases, sales, issuances and settlements			
Purchases	43	5	48
Sales	(12)	—	(12)
Transfers out of Level 3 — Asset	—	(41)	(41)
Balance as of June 30, 2011	$ 34	$ (16)	$ 18
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, 2011	$ —	$ 23	$ 23

(a) Includes the reclassification of $9 million and $15 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, 2011, respectively.

(b) Excludes $65 million of decreases and $2 million of increases in fair value and $108 million and $220 million of realized losses due to settlements associated with Generation's financial swap contract with ComEd and $2 million and $3 million of changes in the fair value of Generation's block contracts with PECO for the three months and six months ended June 30, 2011, respectively. All items eliminate upon consolidation if Exelon's Consolidated Financial Statements.

The following tables present 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, 2012 and 2011:

	Operating Revenue	Purchased Power and Fuel
Total gains (losses) included in income for the three months ended June 30, 2012	$ (96)	$ 29
Total gains (losses) included in income for the six months ended June 30, 2012	$ (9)	$ 27
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2012	$ (22)	$ 21
Change in the unrealized gains relating to assets and liabilities held for the six months ended June 30, 2012	$ 93	$ 10

	Operating Revenue	Purchased Power and Fuel
Total gains included in income for the three months ended June 30, 2011	$ 10	$ 11
Total gains (losses) included in income for the six months ended June 30, 2011	$ 7	$ 1
Change in the unrealized gains relating to assets and liabilities held for the three months ended June 30, 2011	$ 17	$ 13
Change in the unrealized gains relating to assets and liabilities for the six months ended June 30, 2011	$ 21	$ 2

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

Generation

The following tables present assets and liabilities measured and recorded at fair value on Generation's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2012 and December 31, 2011:

As of June 30, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 706	$ —	$ —	$ 706
Nuclear decommissioning trust fund investments				
Cash equivalents	320	—	—	320
Equity				
Equity securities	1,362	—	—	1,362
Commingled funds	—	1,798	—	1,798
Equity funds subtotal	1,362	1,798	—	3,160
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,115	—	—	1,115
Debt securities issued by states of the United States and political subdivisions of the states	—	342	—	342
Debt securities issued by foreign governments	—	73	—	73
Corporate debt securities	—	1,631	—	1,631
Federal agency mortgage-backed securities	—	43	—	43
Commercial mortgage-backed securities (non-agency)	—	39	—	39
Residential mortgage-backed securities (non-agency)	—	12	—	12
Mutual funds	—	8	—	8
Fixed income subtotal	1,115	2,148	—	3,263
Direct lending securities	—	—	54	54
Other debt obligations	—	14	—	14
Nuclear decommissioning trust fund investments subtotal(b)	2,797	3,960	54	6,811
Pledged assets for Zion Station decommissioning				
Equity				
Equity securities	20	—	—	20
Commingled funds	—	18	—	18
Equity funds subtotal	20	18	—	38
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	79	17	—	96
Debt securities issued by states of the United States and political subdivisions of the states	—	60	—	60
Corporate debt securities	—	278	—	278
Federal agency mortgage-backed securities	—	83	—	83
Commercial mortgage-backed securities (non-agency)	—	7	—	7
Commingled funds	—	28	—	28
Fixed income subtotal	79	473	—	552
Direct lending securities	—	—	59	59
Other debt obligations	—	1	—	1
Pledged assets for Zion Station decommissioning subtotal(c)	99	492	59	650

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

As of June 30, 2012	Level 1	Level 2	Level 3	Total
Rabbi trust investments				
Cash equivalents	1	—	—	1
Mutual funds(d)(e)	12	—	—	12
Rabbi trust investments subtotal	13	—	—	13
Commodity mark-to-market derivative assets				
Economic hedges	1,414	5,425	1,327	8,166
Proprietary trading	2,121	4,720	183	7,024
Effect of netting and allocation of collateral(f)	(3,710)	(8,423)	(261)	(12,394)
Commodity mark-to-market assets subtotal(g)	(175)	1,722	1,249	2,796
Interest Rate mark-to-market derivative assets	—	107	—	107
Other investments	2	—	17	19
Total assets	3,442	6,281	1,379	11,102
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,807)	(4,194)	(307)	(6,308)
Proprietary trading	(2,171)	(4,500)	(298)	(6,969)
Effect of netting and allocation of collateral(f)	3,978	7,825	268	12,071
Commodity mark-to-market liabilities subtotal	—	(869)	(337)	(1,206)
Interest rate mark-to-market derivative liabilities	—	(89)	—	(89)
Deferred compensation	—	(25)	—	(25)
Total liabilities	—	(983)	(337)	(1,320)
Total net assets	$ 3,442	$ 5,298	$1,042	$ 9,782

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 466	$ —	$ —	$ 466
Nuclear decommissioning trust fund investments				
Cash equivalents	562	—	—	562
Equity				
Equity securities	1,275	—	—	1,275
Commingled funds	—	1,822	—	1,822
Equity funds subtotal	1,275	1,822	—	3,097
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,014	33	—	1,047
Debt securities issued by states of the United States and political subdivisions of the states	—	541	—	541
Debt securities issued by foreign governments	—	16	—	16
Corporate debt securities	—	778	—	778
Federal agency mortgage-backed securities	—	357	—	357
Commercial mortgage-backed securities (non-agency)	—	83	—	83
Residential mortgage-backed securities (non-agency)	—	5	—	5
Mutual funds	—	47	—	47
Fixed income subtotal	1,014	1,860	—	2,874
Direct lending securities	—	—	13	13
Other debt obligations	—	18	—	18
Nuclear decommissioning trust fund investments subtotal(b)	2,851	3,700	13	6,564

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

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Pledged assets for Zion Station decommissioning				
Equity				
Equity securities	35	—	—	35
Commingled funds	—	30	—	30
Equity funds subtotal	35	30	—	65
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	54	26	—	80
Debt securities issued by states of the United States and political subdivisions of the states	—	65	—	65
Corporate debt securities	—	314	—	314
Federal agency mortgage-backed securities	—	121	—	121
Commercial mortgage-backed securities (non-agency)	—	10	—	10
Commingled funds	—	20	—	20
Fixed income subtotal	54	556	—	610
Direct lending securities	—	—	37	37
Other debt obligations	—	13	—	13
Pledged assets for Zion Station decommissioning subtotal(c)	89	599	37	725
Rabbi trust investments(d)(e)	4	—	—	4
Commodity mark-to-market derivative assets				
Cash flow hedges	—	857	694	1,551
Other derivatives	—	1,653	124	1,777
Proprietary trading	—	240	48	288
Effect of netting and allocation of collateral(f)	—	(1,827)	(28)	(1,855)
Commodity mark-to-market assets subtotal(g)	—	923	838	1,761
Total assets	3,410	5,222	888	9,520
Liabilities				
Commodity mark-to-market derivative liabilities				
Cash flow hedges	—	(13)	—	(13)
Other derivatives	(1)	(1,137)	(13)	(1,151)
Proprietary trading	—	(236)	(28)	(264)
Effect of netting and allocation of collateral(f)	—	1,295	20	1,315
Commodity mark-to-market liabilities subtotal	(1)	(91)	(21)	(113)
Interest rate mark-to-market derivative liabilities	—	(19)	—	(19)
Deferred compensation	—	(18)	—	(18)
Total liabilities	(1)	(128)	(21)	(150)
Total net assets	$3,409	$ 5,094	$ 867	$ 9,370

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

(b) Excludes net assets (liabilities) of $30 million and $(57) million at June 30, 2012 and December 31, 2011, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(c) Excludes net assets of $9 million at December 31, 2011. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(d) The $12 million mutual funds held by the Rabbi trusts are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.

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

(e) Excludes $8 million and $7 million of the cash surrender value of life insurance investments at June 30, 2012 and December 31, 2011, respectively.

(f) Includes collateral postings received from counterparties. Collateral received from counterparties, net of collateral paid to counterparties, totaled $268 million, $(598) million and $7 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of June 30, 2012. Collateral received from counterparties, net of collateral paid to counterparties, totaled $532 million and $8 million allocated to Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2011.

(g) The Level 3 balance includes current and noncurrent assets for Generation of $506 million and $0 million at June 30, 2012 and $503 million and $191 million at December 31, 2011, respectively, 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, 2012 and 2011:

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 unrealized / realized gains (losses)					
Included in income	—	—	(71)(a)	—	(71)
Included in other comprehensive income	—	—	(172)(b)	—	(172)
Included in payable for Zion Station decommissioning	—	(1)	—	—	(1)
Change in collateral	—	—	4	—	4
Purchases, sales, issuances and settlements					
Purchases(c)	41	26	—	3	70
Sales	—	(8)	—	—	(8)
Transfers into Level 3	—	—	(34)		
Transfers out of Level 3	—	—	3	—	3
Balance as of June 30, 2012	$ 54	$ 59	$ 912	$ 17	$1,042
The amount of total losses included in income attributed to the change in unrealized gains related to assets and liabilities held for the three months ended June 30, 2012	$ —	$ —	$ (15)	$ —	$ (15)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(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 unrealized / realized gains (losses)					
Included in income	—	—	3(a)	—	3
Included in other comprehensive income	—	—	(173)(b)	—	(173)
Included in payable for Zion Station decommissioning	—	(1)	—	—	(1)
Change in collateral	—	—	(19)	—	(19)
Purchases, sales, issuances and settlements					
Purchases(c)	41	32	316	17	406
Sales	—	(9)	—	—	(9)
Transfers into Level 3	—	—	(34)		
Transfers out of Level 3	—	—	2	—	2
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 de-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.

Three Months Ended June 30, 2011	Nuclear Decommissioning Trust Fund Investments	Mark-to-Market Derivatives	Total
Balance as of March 31, 2011	$ 31	$ 933	$ 964
Total realized / unrealized losses			
Included in income	—	21(a)	21
Included in other comprehensive income	—	(178)(b)	(178)
Included in payable for Zion Station decommissioning	3	—	3
Changes in collateral	—	2	2
Purchases, sales, issuances and settlements			
Purchases	12	5	17
Sales	(12)	—	(12)
Transfers out of Level 3 — Asset	—	(7)	(7)
Balance as of June 30, 2011	$ 34	$ 776	$ 810
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, 2011	$ —	$ 30	$ 30

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

Six Months Ended June 30, 2011	Nuclear Decommissioning Trust Fund Investments	Mark-to-Market Derivatives	Total
Balance as of December 31, 2010	$ —	$ 1,030	$1,030
Total realized / unrealized gains			
Included in income	—	8(a)	8
Included in other comprehensive income	—	(233)(b)	(233)
Included in payable for Zion Station decommissioning	3	—	3
Changes in collateral	—	7	7
Purchases, sales, issuances and settlements			
Purchases	43	5	48
Sales	(12)	—	(12)
Transfers out of Level 3 — Liability	—	(41)	(41)
Balance as of June 30, 2011	$ 34	$ 776	$ 810
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, 2011	$ —	$ 23	$ 23

(a) Includes the reclassification of $9 million and $15 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, 2011, respectively.

(b) Includes $65 million of decreases in fair value and $2 million of increases in fair value realized losses reclassified from OCI due to settlements of $108 million and $220 million associated with Generation's financial swap contract with ComEd and $2 million and $3 million of decreases in fair value due to settlement of Generation's block contracts with PECO for the three and six months ended June 30, 2011, respectively. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

The following tables present 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, 2012 and 2011:

	Operating Revenue	Purchased Power and Fuel
Total gains (losses) included in income for the three months ended June 30, 2012	$ (101)	$ 30
Total gains (losses) included in income for the six months ended June 30, 2012	$ (25)	$ 28
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2012	$ (36)	$ 21
Change in the unrealized gains relating to assets and liabilities held for the six months ended June 30, 2012	$ 68	$ 10

	Operating Revenue	Purchased Power and Fuel
Total gains included in income for the three months ended June 30, 2011	$ 10	$ 11
Total gains (losses) included in income for the six months ended June 30, 2011	$ 7	$ 1
Change in the unrealized gains relating to assets and liabilities held for the three months ended June 30, 2011	$ 17	$ 13
Change in the unrealized gains relating to assets and liabilities held for the six months ended June 30, 2011	$ 21	$ 2

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

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, 2012 and December 31, 2011:

As of June 30, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 3	$ —	$ —	$ 3
Rabbi trust investments				
Mutual funds	15	—	—	15
Rabbi trust investment subtotal	15	—	—	15
Total assets	18	—	—	18
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark-to-market derivative liabilities(b)(c)	—	—	(617)	(617)
Total liabilities	—	(8)	(617)	(625)
Total net assets (liabilities)	$ 18	$ (8)	$(617)	$(607)

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 173	$ —	$ —	$ 173
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds	19	—	—	19
Rabbi trust investment subtotal	21	—	—	21
Total assets	194	—	—	194
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark-to-market derivative liabilities(b)(c)	—	—	(800)	(800)
Total liabilities	—	(8)	(800)	(808)
Total net assets (liabilities)	$ 194	$ (8)	$(800)	$(614)

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

(b) The Level 3 balance includes the current and noncurrent liability of $506 million and $0 million at June 30, 2012, respectively, and $503 million and $191 million at December 31, 2011, respectively, related to the fair value of ComEd's financial swap contract with Generation which eliminates upon consolidation in Exelon's Consolidated Financial Statements.

(c) The Level 3 balance includes the current and noncurrent liability of $19 million and $92 million at June 30, 2012, respectively, and $9 million and $97 million at December 31, 2011, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

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

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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 and June 30, 2012:

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 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 the fair value of floating-to-fixed energy swap contracts with unaffiliated suppliers for the three and six months ended June 30, 2012, respectively.

Three Months Ended June 30, 2011	Mark-to-Market Derivatives
Balance as of March 31, 2011	$ (875)
Total realized / unrealized gains included in regulatory assets(a)(b)	87
Balance as of June 30, 2011	$ (788)

Six Months Ended June 30, 2011	Mark-to-Market Derivatives
Balance as of December 31, 2010	$ (971)
Total realized / unrealized gains included in regulatory assets(a)(b)	183
Balance as of June 30, 2011	$ (788)

(a) Includes $65 million of increases in fair value and $2 million of decreases in fair value and $108 million and $220 million of realized gains due to settlements associated with ComEd's financial swap contract with Generation for the three and six months ended June 30, 2011, respectively. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

(b) Includes $86 million and $35 million of decreases in fair value of floating-to-fixed energy swap contracts with unaffiliated suppliers for the three and six months ended June 30, 2011, respectively.

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

PECO

The following tables present assets and liabilities measured and recorded at fair value on PECO's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2012 and December 31, 2011:

As of June 30, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 184	$ —	$ —	$184
Rabbi trust investments — mutual funds(b)(c)	8	—	—	8
Total assets	192	—	—	192
Liabilities				
Deferred compensation obligation	—	(18)	—	(18)
Total liabilities	—	(18)	—	(18)
Total net assets (liabilities)	$ 192	$ (18)	$ —	$174

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 175	$ —	$ —	$175
Rabbi trust investments — mutual funds(b)(c)	9	—	—	9
Total assets	184	—	—	184
Liabilities				
Deferred compensation obligation	—	(21)	—	(21)
Total liabilities	—	(21)	—	(21)
Total net assets (liabilities)	$ 184	$ (21)	$ —	$163

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) 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.
(c) Excludes $13 million of the cash surrender value of life insurance investments at June 30, 2012 and December 31, 2011.

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, 2012.

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, 2011:

Three Months Ended June 30, 2011	Mark-to-Market Derivatives
Balance as of March 31, 2011	$ (7)
Total realized gains included in regulatory assets	3(a)
Balance as of June 30, 2011	$ (4)

Six Months Ended June 30, 2011	Mark-to-Market Derivatives
Balance as of December 31, 2010	$ (9)
Total realized gains included in regulatory assets	5(a)
Balance as of June 30, 2011	$ (4)

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

(a) Includes increases of $2 million and $3 million related to the settlement of PECO's block contract with Generation for the three and six months ended June 30, 2011, respectively, which eliminate upon consolidation in Exelon's Consolidated Financial Statements.

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, 2012 and December 31, 2011:

As of June 30, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 25	$ —	$ —	$ 25
Rabbi trust investments — mutual funds	5	—	—	5
Total assets	30	—	—	30
Liabilities				
Deferred compensation obligation	—	(5)	—	(5)
Total liabilities	—	(5)	—	(5)
Total net assets (liabilities)	$ 30	$ (5)	$ —	$ 25

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 33	$ —	$ —	$ 33
Total assets	33	—	—	33
Liabilities				
Total net assets (liabilities)	$ 33	$ —	$ —	$ 33

Valuation Techniques Used to Determine Fair Value

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

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

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to satisfy Generation's 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 on the 15th of the month and the last business day of the month; however, the fund manager may designate any day as a valuation date for the purpose of purchasing or redeeming units. 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 11 — Nuclear Decommissioning for further discussion on the NDT fund investments.

Direct lending funds are investments in managed funds which invest in private companies for long-term capital appreciation. The fair value of these securities is determined using either an enterprise value model or a bond valuation model. Investments in direct lending funds 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.

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. The values of some of these funds are publicly quoted. For fixed-income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2. Fixed-income commingled funds and mutual funds which are publicly quoted, such as money market funds, have been categorized as Level 1 given the clear observability of the prices.

Mark-to-Market Derivatives (Exelon, Generation, ComEd and PECO). 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 8 — 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)

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 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 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 in which 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.

Disclosed below is detail surrounding the Registrants' significant Level 3 valuations. The most significant position is the long term intercompany swap with ComEd, which is further discussed in Note 8 — Derivative Financial Instruments. The calculated fair value includes marketability discounts for margining provisions and notional size. Generation's remaining Level 3 balance generally consists of forward sales and purchases of power and natural gas, coal purchases, and transmission congestion contracts. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

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 the traders and portfolio managers 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 a product of 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 forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is generally less than $4 and $.25 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.

In 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 8 — 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

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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, 2012	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives — Economic Hedges (Generation)(a)	$ 514	Discounted Cash Flow	Forward power price	$9 - $67
			Forward gas price	$2.75 - $7.46
		Option Model	Volatility percentage	25% - 304%
Mark-to-market derivatives — Proprietary trading (Generation)(a)	$ (115)	Discounted Cash Flow	Forward power price	$15 - $75
		Option Model	Volatility percentage	22% - 59%
Mark-to-market derivatives — Transactions with affiliates (Generation and ComEd)(b)	$ 506	Discounted Cash Flow	Marketability reserve	7.9% - 9.5%
		Discounted Cash Flow	Forward heat rate(c)	8.0% - 9.5%
Mark-to-market derivatives (ComEd)	$ (111)		Marketability reserve	3.5% - 8.3%
			Renewable factor	88% - 125%

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 $506 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.

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 us the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give us 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.

8. 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 contracts as well as 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 will no longer utilize 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. 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 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 18 of the Exelon 2011 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, 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.

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, 2012, the percentage of expected generation hedged was 99%-102%, 79%-82%, and 46%-49% for 2012, 2013 and 2014, 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 excluding owned generation to be retired or sold in 2012. 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.

ComEd has locked in a fixed price for a significant portion of its commodity price risk through the five-year financial swap contract with Generation that expires on May 31, 2013, which is discussed in more detail below. In addition, the 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 2 of the Exelon 2011 Form 10-K, qualify for 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.

In order to fulfill a requirement of the Illinois Settlement Legislation, Generation and ComEd entered into a five-year financial swap contract effective August 28, 2007. The financial swap is designed to hedge spot market purchases, which, along with ComEd's remaining energy procurement contracts, meet its load service requirements. The remaining swap contract volume is 3,000 MWs through May 2013. The terms of the financial swap contract require Generation to pay the around-the-clock market price for a portion of ComEd's electricity supply requirement, while ComEd pays a fixed price. The contract is to be settled net, for the difference between the fixed and market pricing, and the financial terms only cover energy costs and do not cover capacity or ancillary services. The financial swap contract is a derivative financial instrument that was originally designated by Generation as a cash flow hedge. As discussed previously, effective with the date of merger with Constellation, Generation de-designated this swap as a cash flow hedge and began recording changes in fair value through current earnings as of that date. Generation records the fair value of the swap on its balance sheet and originally recorded changes in fair value to OCI. The value frozen in OCI as of the date of merger for this swap is reclassified into Generation's earnings as the swap settles. ComEd has not elected hedge accounting for this derivative financial instrument. Since the financial swap contract was deemed prudent by the Illinois Settlement Legislation, ComEd receives full cost recovery for the contract in rates and, therefore, the change in fair value each period is recorded as a regulatory asset or liability on ComEd's Consolidated Balance Sheets. See Note 2 of the Exelon 2011 Form 10-K for additional information regarding the Illinois Settlement Legislation. In Exelon's consolidated financial statements, all financial statement effects of the financial swap recorded by Generation and ComEd are eliminated.

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

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Program, which is further discussed in Note 4 — Regulatory

Matters. Based on Pennsylvania legislation and the DSP Program 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's full requirements contracts and block contracts, which are considered derivatives, qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance. For block contracts designated as normal purchases after inception, the mark-to-market balances previously recorded on PECO's Consolidated Balance Sheet were amortized over the terms of the contracts, which ended on December 31, 2011.

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 normal purchases and normal sales 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 2011 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 2011 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.

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 4,248 GWh and 6,077 GWh for the three and six months ended June 30, 2012, respectively, and 1,496 GWh and 2,829 GWh for the three and six months ended June 30, 2011, respectively, are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's revenue from energy marketing activities. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes.

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

Interest Rate 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 interest rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. For interest rate hedges that qualify and are designated as cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in value of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying interest rate transaction occurs. For interest rate hedges that qualify and are designated as fair value hedges, only the ineffective portion of the derivative gain or loss will impact earnings. Assuming the fair value and cash flow hedges are effective, a hypothetical 50 bps increase in the interest rates associated with variable-rate debt and interest rate swaps would result in less than a $ 2 million decrease in each of Exelon's, Generation's and PECO's pre-tax income for the six months ended June 30, 2012. Below is a summary of the interest rate hedges as of June 30, 2012.

	Generation				Other	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges (a)	Proprietary Trading (a)	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (Current Assets)	$ —	$ 4	$ 16	$ 20	$ —	$ 20
Mark-to-market derivative assets (Noncurrent Assets)	42	9	36	87	14	101
Total mark-to-market derivative assets	$ 42	$ 13	$ 52	$ 107	$ 14	$ 121
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (1)	$ (17)	$ (19)	$ —	$ (19)
Mark-to-market derivative liabilities (Noncurrent Liabilities)	(34)	—	(36)	(70)	(1)	(71)
Total mark-to-market derivative liabilities	$ (35)	$ (1)	$ (53)	$ (89)	$ (1)	$ (90)
Total mark-to-market derivative net assets (liabilities)	$ 7	$ 12	$ (1)	$ 18	$ 13	$ 31

(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 economic hedge and 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 change in market interest rates.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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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	2012	2011	2012	2011
Interest expense(a)	$ (2)	$ —	$ (3)	$ —

(a) For the six months ended June 30, 2012, the loss on the swaps in the table above includes pre-tax losses of $5 million, not related to changes in benchmark interest rates and is excluded from hedge ineffectiveness.

At June 30, 2012 and December 31, 2011, Exelon had $650 million and $100 million, respectively, of notional amounts of fixed-to-floating fair value hedges outstanding related to interest rate swaps, with unrealized gain of $55 million and $14 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, 2012 and June 30, 2011, the impact of loss on the results of operations as a result of ineffectiveness from fair value hedges was $1 million and $0 million, respectively.

At June 30, 2012, Exelon had $150 million of notional amounts of fixed-to-floating interest rate swaps that are marked-to-market, with unrealized gain of $5 million. These swaps, which were acquired as part of the merger with Constellation, expire in 2014. During the period from March 12 to June 30, 2012, the impact on the results of operations was immaterial.

Cash Flow Hedges. In connection with the DOE guaranteed loan for the Antelope Valley acquisition, as discussed in Note 9 — 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 that 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 will be 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, will be amortized as an adjustment to the interest expense over the term of the DOE guaranteed loan.

As Generation draws down on the loan, a portion of the cash flow hedge will be de-designated and the related gains or losses will be reflected in earnings. In order to mitigate this earnings impact, a series of offsetting hedge transactions will be executed as Generation draws on the loan.

Antelope Valley received a loan advance on April 5, 2012, as described in Note 9 — Debt and Credit Agreements. Generation entered into a fixed-to-floating interest rate swap with a notional amount of $52 million, 75% of the loan advance amount to offset a portion of the original interest rate hedge, which is de-designated as a cash flow hedge. The remaining cash flow hedge has a notional amount of $433 million.

At June 30, 2012, Generation's mark-to-market non-current derivative liability relating to the interest rate swap in connection with the loan agreement to fund Antelope Valley was $31 million.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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During the third quarter of 2011, a subsidiary of Constellation entered into floating-to-fixed forward starting interest rate swaps to manage a portion of the interest rate exposure for anticipated long-term borrowings to finance a solar project. The swaps have a total notional amount of $31 million as of June 30, 2012 and expire in 2027. Upon the closing of the merger with Constellation, the swaps were re-designated as cash flow hedges. At June 30, 2012, the subsidiary had a $4 million non-current derivative liability related to these swaps.

During the three and six months ended June 30, 2012 and 2011, the impact on the results of operations as a result of ineffectiveness from cash flow hedges was immaterial.

Fair Value Measurement (Exelon, Generation, ComEd, PECO and BGE)

Fair value accounting guidance 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 master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. In the table below, Generation's cash flow hedges, other derivatives and proprietary trading derivatives are shown gross and the impact of the netting of fair value balances with the same counterparty, as well as netting of collateral, is aggregated in the collateral and netting column. 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.

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The following table provides a summary of the derivative fair value balances recorded by the Registrants as of June 30, 2012:

Derivatives	Generation Economic Hedges(a)	Generation Proprietary Trading	Generation Collateral and Netting(b)	Generation Subtotal (c)	ComEd Economic Hedges (a)(d)	Other Intercompany Eliminations (a)	Exelon Total Derivatives
Mark-to-market derivative assets (current assets)	$ 4,863	$ 5,360	$ (9,073)	$ 1,150	$ —	$ —	$ 1,150
Mark-to-market derivative assets with affiliate (current assets)	506	—	—	506	—	(506)	—
Mark-to-market derivative assets (noncurrent assets)	2,797	1,664	(3,321)	1,140	—	—	1,140
Mark-to-market derivative assets with affiliate (noncurrent assets)	—	—	—	—	—	—	—
Total mark-to-market derivative assets	$ 8,166	$ 7,024	$(12,394)	$ 2,796	$ —	$ (506)	$ 2,290
Mark-to-market derivative liabilities (current liabilities)	$ (4,405)	$ (5,360)	$ 8,974	$ (791)	$ (19)	$ —	$ (810)
Mark-to-market derivative liability with affiliate (current liabilities)	—	—	—	—	(506)	506	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,903)	(1,609)	3,097	(415)	(92)	—	(507)
Mark-to-market derivative liability with affiliate (noncurrent liabilities)	—	—	—	—	—	—	—
Total mark-to-market derivative liabilities	$ (6,308)	$ (6,969)	$ 12,071	$(1,206)	$ (617)	$ 506	$ (1,317)
Total mark-to-market derivative net assets (liabilities)	$ 1,858	$ 55	$ (323)	$ 1,590	$ (617)	$ —	$ 973

(a) Includes current assets for Generation and current liabilities for ComEd of $506 million related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above.
(b) Represents the netting of fair value balances with the same counterparty and the application of collateral.
(c) Current and noncurrent assets are shown net of collateral of $233 million and $424 million, respectively, and current and noncurrent liabilities are shown inclusive of collateral of $(134) million and $(200) million, respectively. The total cash collateral received, net of cash collateral posted and offset against mark-to-market assets and liabilities was $323 million at June 30, 2012.
(d) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

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The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2011:

	Generation					ComEd	Other		Exelon
Derivatives	Cash Flow Hedges (a)	Economic Hedges	Proprietary Trading	Collateral and Netting(b)	Subtotal (c)	Economic Hedges (a)(d)	Economic Hedges	Intercompany Eliminations (a)	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 438	$ 1,195	$ 217	$ (1,418)	$ 432	$ —	$ —	$ —	$ 432
Mark-to-market derivative assets with affiliate (current assets)	503	—	—	—	503	—	—	(503)	—
Mark-to-market derivative assets (noncurrent assets)	419	582	71	(437)	635	—	15	—	650
Mark-to-market derivative assets with affiliate (noncurrent assets)	191	—	—	—	191	—	—	(191)	—
Total mark-to-market derivative assets	$1,551	$ 1,777	$ 288	$ (1,855)	$1,761	$ —	$ 15	$ (694)	$ 1,082
Mark-to-market derivative liabilities (current liabilities)	$ (9)	$ (965)	$ (194)	$ 1,065	$ (103)	$ (9)	$ —	$ —	$ (112)
Mark-to-market derivative liability with affiliate (current liabilities)	—	—	—	—	—	(503)	—	503	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(4)	(186)	(70)	250	(10)	(97)	—	—	(107)
Mark-to-market derivative liability with affiliate (noncurrent liabilities)	—	—	—	—	—	(191)	—	191	—
Total mark-to-market derivative liabilities	$ (13)	$ (1,151)	$ (264)	$ 1,315	$ (113)	$ (800)	$ —	$ 694	$ (219)
Total mark-to-market derivative net assets (liabilities)	$1,538	$ 626	$ 24	$ (540)	$1,648	$ (800)	$ 15	$ —	$ 863

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

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $503 million and $191 million, respectively, related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above. For Generation excludes $19 million noncurrent liability relating to an interest rate swap in connection with a loan agreement to fund Antelope Valley as discussed above.
(b) Represents the netting of fair value balances with the same counterparty and the application of collateral.
(c) Current and noncurrent assets are shown net of collateral of $338 million and $187 million, respectively, and current and noncurrent liabilities are shown inclusive of collateral of $15 million and $0 million, respectively. The total cash collateral received net of cash collateral posted and offset against mark-to-market assets and liabilities was $540 million at December 31, 2011.
(d) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Cash Flow Hedges (Exelon and Generation). Economic hedges that qualify as cash flow hedges primarily consist of forward power sales and power swaps on base load generation. As discussed previously, effective prior to the merger with Constellation, Generation de-designated all of its cash flow hedges relating to commodity price risk. Because the underlying forecasted transactions remain probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be 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 $1,105 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, including approximately $521 million related to the financial swap with ComEd. Generation expects the settlement of the majority of its cash flow hedges, including the ComEd financial swap contract, will occur during 2012 through 2014.

Exelon discontinues hedge accounting prospectively when it determines that the derivative is no longer effective in offsetting changes in the cash flows of a hedged item, in the case of forward-starting hedges, or when it is no longer probable that the forecasted transaction will occur. For the three months ended June 30, 2012 and 2011, 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, 2012, containing information about the changes in the fair value of cash flow hedges and the reclassification from accumulated OCI into results of operations. The amounts reclassified from accumulated OCI, when combined with the impacts of the actual physical power sales, result in the ultimate recognition of net revenues at the contracted price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended June 30, 2012	**Income Statement Location**	**Energy-Related Hedges**	**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)
Ineffective portion recognized in income	Operating Revenues	—	—
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.

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

(b) Includes $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.
(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 the de-designation of all commodity cash flow positions prior to the merger date, there are no changes in fair value.

Six Months Ended June 30, 2012	Income Statement Location	Total Cash Flow Hedge OCI Activity, Net of Income Tax — Generation Energy-Related Hedges	Total Cash Flow Hedge OCI Activity, Net of Income Tax — 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
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 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.

Three Months Ended June 30, 2011	Income Statement Location	Total Cash Flow Hedge OCI Activity, Net of Income Tax — Generation Energy-Related Hedges	Total Cash Flow Hedge OCI Activity, Net of Income Tax — Exelon Total Cash Flow Hedges
Accumulated OCI derivative gain at March 31, 2011		$ 941(a)	$ 354
Effective portion of changes in fair value		(106)(b)	(64)
Reclassifications from accumulated OCI to net income	Operating Revenues	(143)(c)	(77)
Ineffective portion recognized in income	Operating Revenues	(4)	(4)
Accumulated OCI derivative gain at June 30, 2011		$ 688(a)(d)	$ 209

(a) Includes $458 million and $562 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, $1 million and $2 million of gains, net of taxes, related to the fair value of the block contracts with PECO as of June 30, 2011 and March 31, 2011, respectively.
(b) Includes a $39 million gain, net of taxes, related to the effective portion of changes in fair value of the five-year financial swap contract with ComEd for the three months ended June 30, 2011. The PECO block contracts were designated as normal sales as of May 31, 2010. As such, there were no effective changes in fair value of the block contracts with PECO for the three months ended June 30, 2011 as the mark-to-market balances previously recorded will be amortized over the term of the contract.

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

(c) Includes a $65 million loss, 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, and a $1 million loss, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the fair value of the block contracts with PECO for the three months ended June 30, 2011.
(d) Excludes $2 million of gains, net of taxes, related to interest rate swaps and treasury rate locks.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
Six Months Ended June 30, 2011	Income Statement Location	Generation Energy-Related Hedges	Exelon Total Cash Flow Hedges
Accumulated OCI derivative gain at December 31, 2010		$ 1,011(a)	$ 400
Effective portion of changes in fair value		(43)(b)	(46)
Reclassifications from accumulated OCI to net income	Operating Revenues	(275)(c)	(140)
Ineffective portion recognized in income	Operating Revenues	(5)	(5)
Accumulated OCI derivative gain at June 30 2011		$ 688(a)(d)	$ 209

(a) Includes $458 million and $589 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, and $1 million and $3 million of gains, net of taxes, related to the fair value of the block contracts with PECO as of June 30, 2011 and December 31, 2010, respectively.
(b) Includes a $2 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 for the six months ended June 30, 2011. The PECO block contracts were designated as normal sales as of May 31, 2010. As such, there were no additional effective changes in fair value of PECO's block contracts as the mark-to-market balances previously recorded are being amortized over the term of the contract.
(c) Includes a $133 million loss, 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 and a $2 million loss, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the fair value of the block contracts with PECO for the six months ended June 30, 2011.
(d) Excludes $2 million of gains, net of taxes, related to interest rate swaps.

During the three and six months ended June 30, 2012, Generation's cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $402 million and a $722 million pre-tax gain, respectively, and a $237 million and $454 million pre-tax gain for the three and six months ended June 30, 2011. Given that the cash flow hedges had primarily consisted of forward power sales and power swaps and did not include 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, primarily due to changes in market prices were $5 million for the six months ended June 30, 2012. There was no ineffectiveness for the three months ended June 30, 2012 as Generation will not incur changes in cash flow hedge ineffectiveness in future periods as all commodity cash flow hedge positions were de-designated prior to the merger date.

Exelon's energy-related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $230 million and $403 million pre-tax gain for the three and six months ended June 30, 2012, respectively, and a $127 million and $231 million pre-tax gain for the three and six months ended 2011, respectively. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices, were $5 million for the six months ended June 30, 2012. There was no ineffectiveness for the three months ended June 30, 2012 as Generation will not incur changes in cash flow hedge ineffectiveness in future periods as all commodity cash flow hedge positions were de-designated prior to the merger date.

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Economic Hedges (Exelon and Generation). These instruments represent hedges that mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, and physical forward sales and purchases. For the three and six months ended June 30, 2012 and 2011, 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, 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 gains (losses)	$ (10)	$ 210	$ 200	$ 6	$ 206

	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 gains	$ 68	$ 197	$ 265	$ 17	$ 282

	Exelon and Generation		
Three Months Ended June 30, 2011 (As Reported)	**Operating Revenues**	**Purchased Power and Fuel**	**Total**
Change in fair value	$ —	$ (4)	$ (4)
Reclassification to realized at settlement	—	(126)	(126)
Net mark-to-market (losses)(b)	$ —	$ (130)	$(130)

	Exelon and Generation		
Six Months Ended June 30, 2011 (As Reported)	**Operating Revenues**	**Purchased Power and Fuel**	**Total**
Change in fair value	$ —	$ (7)	$ (7)
Reclassification to realized at settlement	—	(273)	(273)
Net mark-to-market (losses)(b)	$ —	$ (280)	$(280)

	Exelon and Generation		
Three Months Ended June 30, 2011 (Pro Forma)	**Operating Revenues**	**Purchased Power and Fuel**	**Total**
Change in fair value	$ 12	$ (16)	$ (4)
Reclassification to realized at settlement	(137)	11	(126)
Net mark-to-market (losses)(b)	$ (125)	$ (5)	$(130)

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

Six Months Ended June 30, 2011 (Pro Forma)	Exelon and Generation Operating Revenues	Exelon and Generation Purchased Power and Fuel	Exelon and Generation Total
Change in fair value	$ 13	$ (20)	$ (7)
Reclassification to realized at settlement	(271)	(2)	(273)
Net mark-to-market (losses)(b)	$ (258)	$ (22)	$(280)

(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.

(b) Exelon and Generation have historically presented mark-to-market gains and losses within purchased power expense for all non-trading, energy-related derivatives that were not accounted for as cash flow hedges. In 2011, Exelon and Generation classified the mark-to-market gains and losses for contracts, where the underlying hedged transaction was an expected sale to hedge power, to operating revenues.

Proprietary Trading Activities (Exelon and Generation). For the three and six months ended June 30, 2012 and 2011, 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, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Change in fair value	Operating Revenue	$ 12	$ 16	$ 14	$ 19
Reclassification to realized at settlement	Operating Revenue	31	(7)	32	(12)
Net mark-to-market gains	Operating Revenue	$ 43	$ 9	$ 46	$ 7

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 that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings 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

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

department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of June 30, 2012. 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 $61 million, $59 million and $11 million, respectively.

Rating as of June 30, 2012	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	$ 2,523	$ 802	$ 1,721	—	$ —
Non-investment grade	88	41	47	—	—
No external ratings					
Internally rated — investment grade	552	16	536	1	286
Internally rated — non-investment grade	64	7	57	—	—
Total	$ 3,227	$ 866	$ 2,361	1	$ 286

Net Credit Exposure by Type of Counterparty	As of June 30, 2012
Investor-owned utilities, marketers and power producers	$ 1,091
Energy cooperatives and municipalities	775
Financial institutions	406
Other	89
Total	$ 2,361

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, 2012, ComEd's credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation as well as the ICC-approved procurement tariffs. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 2 of the Exelon 2011 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, 2012, PECO had no net credit exposure to suppliers.

PECO is permitted to recover its costs of procuring electric supply through its PAPUC-approved DSP Program. PECO's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 4 — 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; however, the natural gas asset managers have provided $14 million in parental guarantees related to these agreements. As of June 30, 2012, PECO had credit exposure of $4 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 6 of BGE's 2011 Form 10-K 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, 2012, 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' demand, which are not covered by the gas cost adjustment clause. At June 30, 2012, 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 and emissions allowances. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on NYMEX, ICE, and Nodal Exchanges ("the exchanges"). 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. 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, 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)
($4,126)	$3,235	($891)

Credit-Risk Related Contingent Feature		December 31, 2011
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)
($1,014)	$928	($86)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features that are not fully collateralized by posted cash collateral on an individual, contract-by-contract basis 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 has cash collateral posted of $697 million and letters of credit posted of $1,189 million and cash collateral held of $1,007 million and letters of credit held of $152 million as of June 30, 2012 and cash collateral held of $542 million and letters of credit held of $89 million at December 31, 2011. In the event of a credit downgrade below investment grade (i.e. BB+ or Ba1), Exelon Generation Company, LLC and Constellation Energy Commodities Group, Inc. could be required to post additional collateral of $2,375 million as of June 30, 2012 and $1,612 million as of December 31, 2011. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation'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, 2012, Generation's swaps were in an asset position, with a fair value of $18 million.

See Note 18 of the Exelon 2011 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 the financial swap contract between Generation and ComEd, if a party is downgraded below investment grade by Moody's or S&P, collateral postings would be required by that party depending on how market prices compare to the benchmark price levels. Under the terms of the financial swap contract, collateral postings will never exceed $200 million from either ComEd or Generation. 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, 2012, ComEd held both cash and letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts. These amounts were not material. 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, 2012, ComEd held approximately $20 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. See Note 2 of the Exelon 2011 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, 2012, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of June 30, 2012, PECO could have been required to post approximately $36 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, 2012, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of June 30, 2012, BGE could have been required to post approximately $54 million of collateral to its counterparties.

Exelon's interest rate swaps contain provisions that, in the event of a merger, if Exelon'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 less charges.

Accounting for the Offsetting of Amounts Related to Certain Contracts (Exelon and Generation)

As of June 30, 2012 and December 31, 2011, $13 million and $2 million, respectively, of cash collateral received was not offset against derivative positions, because they were not associated with energy-related derivatives.

9. 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. Exelon had bank lines of credit under committed credit facilities at June 30, 2012 for short-term financial needs, as follows:

Type of Credit Facility	Amount(a) (In billions)	Expiration Dates	Capacity Type
Exelon Corporate			
Syndicated Revolver	$ 2.00	October 2013 to March 2016	Letters of credit and cash
Bilateral	0.90	September 2013 to December 2014	Letters of credit and cash
Generation			
Syndicated Revolver	5.30	March 2016	Letters of credit and cash
Bilateral	0.30	December 2015 and March 2016	Letters of credit and cash
ComEd			
Syndicated Revolver	1.00	March 2017	Letters of credit and cash
PECO			
Syndicated Revolver	0.60	March 2016	Letters of credit and cash
BGE			
Syndicated Revolver	0.60	March 2015	Letters of credit and cash
Total	$ 10.70		

(a) Excludes $118 million of credit facility agreements arranged with minority and community banks at Generation, ComEd and PECO. These facilities, which expire in October 2012, are solely utilized to issue letters of credit.

As of June 30, 2012, there were no borrowings under the Registrants' credit facilities.

The Registrants had the following amounts of commercial paper borrowings outstanding as of June 30, 2012 and December 31, 2011:

Commercial Paper Borrowings	June 30, 2012	December 31, 2011
Exelon Corporate	$ 188	$ 161
Generation	—	—
ComEd	178	—
PECO	—	—
BGE	—	—

ComEd Credit Facility

On March 28, 2012, ComEd replaced its unsecured revolving credit facility with a new unsecured 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 has an initial term expiring on March 28, 2017, and ComEd may request up to two, one-year extensions 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 extensions or increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. ComEd incurred $3 million in costs related to the replacement of the credit facility. These costs included upfront arranger fees and filing costs, which will be amortized to interest expense over the term of the credit facility.

Borrowings under the credit agreement may bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon ComEd's credit rating. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreement requires ComEd to pay a facility fee based upon the aggregate commitments under the agreement. The maximum facility fee is 35 basis points. The fee varies depending upon ComEd's credit rating. As of June 30, 2012, ComEd adders were 27.5 basis points and 127.5 basis points for prime rate and LIBOR-based rate borrowings, respectively.

Exelon Credit Facilities

In connection with the Upstream Merger, Exelon assumed all of Constellation's obligations under its three-year, unsecured revolving credit facility (the "Constellation Credit Agreement"). Effective as of the Initial Merger, the Constellation Credit Agreement was amended and restated to (1) permit Exelon and Constellation to consummate the Upstream Merger and the restructuring transaction, (2) reduce the aggregate commitments under the Constellation Credit Agreement from $2.5 billion to $1.5 billion, and (3) conform some of the representations, warranties, covenants and events of default in the Constellation Credit Agreement with representations, warranties, covenants and events of default in the Exelon credit agreement, dated as of March 23, 2011, as amended as of the Initial Merger. In connection with the Upstream Merger, Exelon also assumed Constellation's obligations under four separate bilateral credit facilities and a commodity-linked credit facility, which were also amended to conform with the Constellation Credit Agreement effective as of the Initial Merger. Effective as of the Initial Merger, the Exelon Credit Agreement and the Generation Credit Agreement were amended and restated to conform some of the representations, warranties and covenants with provisions of the Constellation Credit Agreement, as amended effective as of the Initial Merger. See Note 3 — Merger and Acquisitions for further description of the merger transaction.

On July 18, 2012, Exelon Corporate, Generation, PECO and BGE began the process of amending and 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 amended credit facilities will reflect current market pricing and maturities of five years from the close of the transactions. The transactions are expected to close and become effective in August 2012. 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. The maturity of the $1.5 billion Constellation Credit Agreement will be amended to December 31, 2012.

Long-Term Debt

On June 18, 2012, Generation issued and sold $775 million of Senior Notes. In connection with this debt issuance, Generation entered into forward-starting interest rate swaps in the aggregate notional amount of $470 million. The interest rate swaps were settled on June 15, 2012 with Generation recording a pre-tax loss of approximately $7 million. The loss was recorded to other comprehensive income within Exelon's and Generation's Consolidated Balance Sheets and will be amortized to income over the life of the related debt as an increase to interest expense.

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

Concurrently with the new debt issuance, Generation engaged in private offers (the Exchange Offer) to certain eligible holders to exchange any and all of the $700 million outstanding 7.60% Senior Notes due 2032 (Old Notes) of Exelon (which were assumed by Exelon in the merger with Constellation), for:

- Generation's newly issued 4.25% Senior Notes due 2022, plus a cash payment; and
- Generation's newly issued 5.60% Senior Notes due 2042, plus a cash payment.

On June 28, 2012, pursuant to the Exchange Offer, Generation purchased $441 million of the Old Notes in exchange for issuing $535 million of Notes due in 2022 and 2042, plus a cash payment of approximately $60 million. The $441 million of Old Notes were recorded on Exelon's Consolidated Balance Sheets at $608 million, reflecting a fair value adjustment pursuant to the application of purchase accounting applied as a result of the Constellation merger which resulted in approximately $13 million gain from the Exchange Offer at Generation. The gain was recorded as an increase to Long-term Debt within Exelon's and Generation's Consolidated Balance Sheets and will be amortized to income over the life of the debt as a reduction in interest expense.

On July 13, 2012, pursuant to the Exchange Offer described above, Generation purchased an additional $1 million of Old Notes in exchange for the Senior Notes due in 2022 and 2042.

In connection with the debt obligations assumed by Exelon as part of the Upstream Merger on March 12, 2012, 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 included in Long-term Debt on Generation's Consolidated Balance Sheets and intercompany notes receivable at Exelon Corporate, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets. The third-party debt obligations are reported in Long-term Debt on Exelon's Consolidated Balance Sheets. The intercompany loan agreements are summarized as follows:

- $700 million aggregate principal amount of Old Notes, $259 million of which was outstanding as of June 30, 2012 after the Exchange Offer described above;
- $550 million aggregate principal amount of 4.55% Fixed-Rate Notes due 2015, all of which was outstanding as of June 30, 2012;
- $450 million aggregate principal amount of 8.625% Series A Junior Subordinated Debentures due 2063, all of which was outstanding as of June 30, 2012; and
- $550 million aggregate principal amount of 5.15% Notes due 2020, all of which was outstanding as of June 30, 2012.

The intercompany loan agreements and the third-party debt obligations described above were increased by $403 million for a fair value adjustment pursuant to the application of purchase accounting applied as a result of the Constellation merger, of which $224 million was outstanding as of June 30, 2012, primarily reflecting the Exchange Offer described above. This premium is being amortized over the lives of the arrangements as a reduction to interest expense.

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

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Issuance of Long-Term Debt

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 2, 2037	$ 69	Funding for AVSR solar development

During the six months ended June 30, 2011, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
ComEd	First Mortgage Bonds	1.625%	January 15, 2014	$ 600	Used as an interim source of liquidity for January 2011 contribution for Exelon-sponsored pension plans in which ComEd participates and for other general corporate purposes.

Retirement of Long-Term Debt

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	Armstrong Co. tax-exempt	5.00%	December 1, 2042	$ 46
Exelon	Senior Notes	7.60%	April 1, 2032	$ 441
Exelon	Medium Term Notes	7.30%	June 1, 2012	$ 2

During the six months ended June 30, 2011, the following long-term debt was retired:

Company	Type	Interest Rate	Maturity	Amount
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 1
ComEd	Sinking fund debentures	4.75%	December 1, 2011	1

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

Accounts Receivable Agreement

PECO is party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its customer accounts receivable designated under the agreement in exchange for proceeds of $225 million, which is classified as a short-term note payable on Exelon's and PECO's Consolidated Balance Sheets. As of June 30, 2012 and December 31, 2011, the financial institution's undivided interest in Exelon's and PECO's gross customer accounts receivable was equivalent to $296 million and $329 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 institution's undivided interest. Effective April 30, 2012, PECO and the financial institution entered into an amendment to the agreement, which modified certain eligibility criteria that increased the amount of PECO's receivables that will be considered eligible receivables under the agreement for purposes of satisfying this requirement. Upon termination or liquidation of this agreement, the financial institution is entitled to recover up to $225 million plus the accrued yield payable from its undivided interest in PECO's receivables. On September 2, 2011, PECO extended this agreement until August 31, 2012, unless extended in accordance with its terms. As of June 30, 2012, 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.

Antelope Valley Project Development Debt Agreement

On April 5, 2012, Antelope Valley received the first DOE-guaranteed loan advance of $69 million at an interest rate spread of 37.5 basis points above U.S. Treasury and maturity of January 5, 2037. The loan advance terminated the put option that Generation had on the Antelope Valley project. As a result, Generation entered into a fixed-to-floating interest rate swap with a notional amount of $52 million, 75% of the first loan advance amount to offset a portion of the original interest rate hedge. See Note 8 — Derivative Financial Instruments for additional information on the interest rate swap.

In addition, Generation has issued letters of credit to support its equity investment in the project. As of June 30, 2012, Generation had $669 million in letters of credit outstanding related to the project The letters of credit balance is expected to decline over time as scheduled equity contributions for the project are made.

10. 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, 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	(0.7)	(0.7)	(0.8)	(0.3)	(1.7)
Plant basis differences	(0.7)	—	0.1	(3.6)	(4.7)
Production tax 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%

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

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	(0.7)	(0.6)	(0.5)	(0.3)	3.8
Plant basis differences	(0.6)	—	—	(3.6)	10.6
Production tax credits	(2.6)	(3.4)	—	—	—
Fines & 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%

For the Three Months Ended June 30, 2011	Exelon	Generation	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	2.0	3.0	3.2	1.5	5.2
Qualified nuclear decommissioning trust fund income	1.3	1.9	—	—	—
Domestic production activities deduction	(1.0)	(1.5)	—	—	—
Tax exempt income	(0.2)	(0.2)	—	—	—
Health Care Reform Legislation	—	—	(4.8)	—	2.8
Amortization of investment tax credit	(0.2)	(0.2)	(0.4)	(0.3)	(0.9)
Plant basis differences	—	—	0.2	(0.1)	(2.2)
Production tax credits	(0.9)	(1.5)	—	—	—
Other	(1.1)	(1.8)	0.5	0.1	3.0
Effective income tax rate	34.9%	34.7%	33.7%	36.2%	42.9%

For the Six Months Ended June 30, 2011	Exelon	Generation	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	3.9	4.7	4.9	(1.6)	4.7
Qualified nuclear decommissioning trust fund income	1.8	2.6	—	—	—
Domestic production activities deduction	(1.0)	(1.4)	—	—	—
Tax exempt income	(0.1)	(0.2)	—	—	—
Health Care Reform Legislation	—	—	(2.8)	—	(1.0)
Amortization of investment tax credit	(0.2)	(0.2)	(0.4)	(0.3)	(0.3)
Plant basis differences	—	—	(0.1)	(0.2)	(1.0)
Production tax credits	(0.9)	(1.3)	—	—	—
Other	(0.8)	(1.4)	0.3	(0.2)	—
Effective income tax rate	37.7%	37.8%	36.9%	32.7%	37.4%

(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 and 2011. 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 $1,050 million, $885 million, $68 million, $48 million, and $10 million, respectively, of unrecognized tax benefits as of June 30, 2012. Exelon's, Generation's, ComEd's, PECO's and BGE's uncertain tax positions have not significantly changed since December 31, 2011. See Note 11 of the Exelon 2011 Form 10-K and Note 10 of the 2011 Form 10-K for Constellation and BGE for further discussion of reasonably possible changes that could occur in unrecognized tax benefits during the next twelve months.

Other Income Tax Matters

IRS Appeals 1999-2001 (Exelon, ComEd and PECO)

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 1999 sale of ComEd's fossil generating assets. Exelon deferred approximately $1.6 billion of the gain under the involuntary conversion provisions of the IRC. 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. Exelon received the IRS audit report for 1999 through 2001, which reflected the full disallowance of the deferral of gain associated with both the involuntary conversion position and the like-kind exchange transaction.

Competitive Transition Charges (Exelon, ComEd, and PECO). Exelon filed refund claims with the IRS taking the position that CTCs collected during ComEd's and PECO's transition periods represented compensation for a taking of their respective properties 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 Tax Positions. In the third quarter of 2010, Exelon and IRS Appeals reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion and CTC positions. The agreement includes IRS Appeals' agreement to withdraw its assertion of the $110 million substantial understatement penalty with respect to Exelon's involuntary conversion position. As a result of the preliminary agreement, Exelon and ComEd eliminated any liability for unrecognized tax benefits associated with the settled positions and established a current tax payable to the IRS. In the second quarter of 2012, IRS Appeals submitted the final terms, calculations, and definitive agreements to the Joint Committee on Taxation for its review.

Under the terms of the agreement, Exelon estimates that the IRS will assess tax and interest of approximately $300 million in 2012 for the years for which there is a resulting tax deficiency, of which $405 million is attributable to ComEd, ($135) million to PECO, $10 million to Generation and the remainder to Exelon. These amounts are net of approximately $300 million of refunds due from the settlement of the 2001 tax method of accounting change for certain overhead costs under the SSCM as well as other agreed upon audit adjustments. In order to stop additional interest from accruing on the expected assessment, Exelon made a payment in December 2010 to the IRS of $302 million.

Exelon and IRS Appeals to date have failed to reach a settlement with respect to 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. Exelon continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO and does not believe that the concession demanded by the IRS in its settlement offer reflects the strength of Exelon’s position. IRS Appeals also continues to assert an $86 million penalty for a substantial understatement of tax with respect to the like-kind exchange position.

While Exelon has been and remains willing to settle the issue in a manner generally commensurate with its hazards of litigation, the IRS has thus far been unwilling to settle the issue without requiring a nearly complete concession of the issue by Exelon. Accordingly, to continue to contest the IRS’s disallowance of the like-kind exchange position and its assertion of the $86 million substantial understatement penalty, Exelon expects to initiate litigation in 2013. Given that Exelon has determined settlement is not a realistic outcome, it has assessed, in accordance with applicable accounting standards, whether it will prevail in litigation. While Exelon recognizes the complexity and hazards of this litigation, it believes that it is more likely than not that it will prevail in such litigation and, therefore, eliminated any liability for unrecognized tax benefits. Further, Exelon believes it is unlikely that the penalty assertion will ultimately be sustained. Exelon and ComEd have not recorded a liability for penalties. However, should the IRS prevail in asserting the penalty, it would result in an after-tax charge of $86 million to Exelon’s and ComEd’s results of operations.

As of June 30, 2012, assuming Exelon’s settlement of the involuntary conversion position is finalized, the potential tax and interest, exclusive of penalties, that could become currently payable in the event of a fully successful IRS challenge to Exelon’s like-kind exchange position could be as much as $860 million, of which $510 million would be paid by ComEd and the remainder by Exelon. If the IRS were to prevail in litigation on the like-kind exchange position, Exelon’s results of operations could be negatively affected due to increased interest expense, as of June 30, 2012, by as much as $260 million, net of tax, of which $160 million would be recorded at ComEd and the remainder by Exelon. Litigation could take several years such that the estimated cash and interest impacts would likely change by a material amount.

Long-Term State Tax Apportionment (Exelon and Generation)

Exelon and Generation periodically review events that may significantly impact how income is apportioned among the states and, therefore, the calculation of their respective deferred state income taxes. Events that may require Exelon and Generation to update their long-term state tax apportionment include significant changes in tax law and/or significant operational changes, such as the merger with Constellation. As a result of the merger, Exelon and Generation reevaluated their long-term state tax apportionment for all states where they have state income tax obligations, which include Illinois, Maryland and Pennsylvania, as well as other states. The total effect of revising the long-term state tax apportionment resulted in the recording of a deferred state tax asset of $72 million (net of Federal taxes) for Exelon. Of this, a benefit in the amount of $116 million and $14 million (net of Federal taxes) was recorded for Exelon and Generation, respectively, for the first quarter of 2012. Further, Exelon and Generation recorded deferred state tax liabilities of $44 million and $14 million (net of Federal taxes), respectively, as part of purchase accounting during the first quarter of 2012.

Accounting for Gas Distribution Property Repairs (Exelon, PECO and BGE).

Exelon currently anticipates that the IRS will issue guidance during 2012 providing a safe harbor method of tax accounting for gas distribution property to determine the tax treatment of repair costs for gas distribution assets. If PECO and BGE choose to change to a new gas distribution repair methodology, management anticipates it would likely result in an earnings and cash tax benefit at PECO. The effect at BGE is expected to be immaterial.

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

PECO's approved 2010 natural gas distribution rate case settlement stipulates that the expected cash benefit resulting from the application of the new methodology to prior tax years must be refunded to customers over a seven-year period. The prospective tax benefit claimed as a result of the new methodology should be reflected in tax expense in the year in which it is claimed on the tax return and will be reflected in the determination of revenue requirements in the next natural gas distribution base rate case. See Note 2 of the Exelon 2011 Form 10-K for further information on the impact of the guidance on natural gas distribution base rate cases.

Interest Expense on Income Taxes (BGE)

For the three and six months ended June 30, 2012, BGE recorded an adjustment to interest expense of approximately $1 million and $7 million, respectively, to reflect the impacts of anticipated amendments of tax positions previously taken on prior-year consolidated income tax returns. BGE has concluded this adjustment is not material to its results of operations or cash flows for the three and six months ended June 30, 2012, or any prior period.

11. 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.

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets from December 31, 2011 to June 30, 2012:

Nuclear decommissioning ARO at December 31, 2011(a)	$3,680
Accretion expense	111
Net increase due to changes in estimated cash flows	80
Costs incurred to decommission retired plants	(1)
Nuclear decommissioning ARO at June 30, 2012(a)	$3,870

(a) Includes $6 million and $5 million as the current portion of the ARO at June 30, 2012 and December 31, 2011, respectively, which is included in other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

During the six months ended June 30, 2012, Generation's ARO increased by $190 million, primarily due to increases for accretion and a net increase of $80 million due to changes in estimated cash flows primarily related to increased costs resulting from an updated decommissioning cost study received for the Quad Cities generating station. The increase due to the changes in estimated cash flows had no impact to Exelon's or Generation's Consolidated Statements of Operations and Comprehensive Income.

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generating station unit to satisfy Generation's nuclear decommissioning obligations. 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

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PECO nuclear plants through regulated rates, and these collections may continue through the operating lives of the plants. The amounts collected from PECO customers are remitted to Generation and 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. On March 30, 2012, PECO filed its Nuclear Decommissioning Cost Adjustment with the PAPUC proposing an annual recovery from customers of $24 million, which reflects a reduction from the current approved annual collections of $29 million. On July 23, 2012, the PAPUC approved the filing and the new rates will be effective January 1, 2013. See Note 12 of the Exelon 2011 Form 10-K for information regarding amounts collected from PECO customers for decommissioning costs. See below for discussion of NRC minimum funding requirements.

In the first half of 2012, the NDT fixed income portfolio completed the transition from solely core fixed income investments to a blend of Treasury Inflation Protected Securities (TIPS), investment-grade corporate credit and short-term corporate lending. There was no change in the equity investment strategy.

At June 30, 2012 and December 31, 2011, Exelon and Generation had NDT fund investments totaling $6,841 million and $6,507 million, respectively. The following table provides unrealized gains (losses) on NDT funds for the three and six months ended June 30, 2012 and 2011:

	Exelon and Generation			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Net unrealized gains (losses) on decommissioning trust funds — Regulatory Agreement Units(a)	$ (96)	$ 28	$ 150	$ 140
Net unrealized gains (losses) on decommissioning trust funds — Non-Regulatory Agreement Units(b)(c)	(35)	11	30	54

(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 $4 million and $22 million of net unrealized gains related to the Zion Station pledged assets for the three months ended June 30, 2012 and 2011, respectively, and $38 million and $45 million of net unrealized gains related to the Zion Station pledged assets for the six months ended June 30, 2012 and 2011, 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, which are subject to regulatory accounting, are eliminated within Other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

See Note 2 of the Exelon 2011 Form 10-K for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning. On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. See Note 12 of the Exelon 2011 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, four 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. The matter is currently under review by the court.

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 $67 million, which is included within the nuclear decommissioning ARO at June 30, 2012. Generation also has retained a requisite level of NDT assets to fund its obligation to maintain and transfer the SNF at Zion Station. As of June 30, 2012, the carrying value of the Zion Station pledged assets and the payable to ZionSolutions was approximately $650 million and $604 million, respectively. The payable 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. The current portion of the payable to ZionSolutions, included in other current liabilities within Exelon's and Generation's Consolidated Balance Sheets at June 30, 2012 and December 31, 2011 was $141 million and $128 million, respectively.

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 March 31, 2011, Generation, in its NRC-required biennial decommissioning funding status report, provided data from which the NRC concluded that the amount of decommissioning funding as of December 31, 2010 for Limerick Unit 1 was less than the amount required by the NRC's regulations. Generation performed the calculations again in early 2012, which reflected that the amount of decommissioning funding as of December 31, 2011 for Limerick Unit 1 was less than the amount required by the NRC's regulations. In February 2012, Generation obtained a parent guarantee in the amount of $115 million to cover the NRC minimum funding assurance requirements for Limerick Unit 1 and informed the NRC that it had addressed the minimum funding issues by, among other things, obtaining the parent guarantee. In a letter dated June 28, 2012, the NRC advised Generation of the NRC's determination that the amount of decommissioning financial assurance provided in Generation's plan was equal to or greater than the minimum required under the

NRC regulations and that Generation had provided reasonable assurance that funds would be available for the Limerick Unit 1 decommissioning process.

12. 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. Effective March 12, 2012, Exelon became the sponsor of all of Constellation's defined benefit pension and other postretirement benefit plans and defined contribution savings plans. As of that date, the legacy Constellation pension and other postretirement benefit plans were remeasured using current assumptions including the discount rate.

Defined Benefit Pension and Other Postretirement Benefits

During the first quarter of 2012, Exelon received an updated valuation of its legacy pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2012. This valuation resulted in an increase to the pension and other postretirement benefit obligations of $86 million and $25 million, respectively. Additionally, accumulated other comprehensive loss increased by approximately $8 million (after tax) and regulatory assets increased by $98 million.

During the second quarter of 2012, Exelon received an updated valuation of legacy Constellation's pension and postretirement benefit obligations to reflect actual census data as of the merger date. This valuation resulted in an increase and a decrease to the pension and other postretirement benefit obligations of $1 million and $19 million, respectively. Additionally, accumulated other comprehensive loss decreased by approximately $3 million (after-tax) and regulatory assets decreased by approximately $13 million.

As a result of employee severances related to the merger, a curtailment was triggered for certain legacy Constellation pension and other postretirement benefit plans in the second quarter of 2012. Accordingly, the benefit obligation and plan assets for those plans were remeasured using assumptions as of June 30, 2012, including updated discount rates, asset values, and planned changes to the method of obtaining prescription drug subsidies. The discount rates used to calculate the curtailed pension and other postretirement benefit plan obligations as of June 30, 2012 were 3.97% and 3.98%, respectively. These discount rates were used to calculate the remainder of year costs for the curtailed plans. The curtailment and associated remeasurement resulted in an increase and a decrease to the unfunded status of the pension and other postretirement benefit plans of $84 million and $32 million, respectively. Additionally, accumulated other comprehensive loss increased by approximately $6 million (after-tax) and regulatory assets increased by approximately $44 million. Exelon also recognized a $2 million curtailment gain for legacy Constellation's other postretirement benefit plans in the second quarter of 2012, of which Generation recognized a $1 million curtailment gain.

Under Exelon's and Constellation's severance plans, certain severed employees were offered additional pension and other postretirement benefits. As a result, Exelon recorded contractual termination benefit charges of $20 million in the second quarter of 2012, of which Generation and BGE recorded $9 million and $3 million, respectively. BGE recorded its portion of the contractual termination benefit charge of $3 million along with $1 million that was billed to it by BSC as a regulatory asset, consistent with prior MDPSC precedent. ComEd recorded the $1 million of contractual termination benefit charge that was billed to it by BSC as a regulatory asset pursuant to EIMA.

The following tables present the components of Exelon's net periodic benefit costs for the three and six months ended June 30, 2012 and 2011. The 2012 pension benefit cost is calculated using an expected long-term rate of return on plan assets of 7.50% for all plans and discount rates of 4.74% and 4.27% for legacy Exelon and Constellation plans, respectively. The 2012 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.68% for funded plans, and discount rates of 4.80% and 4.28% for legacy Exelon and Constellation plans, respectively. Legacy Constellation other postretirement plans are not funded. As discussed above, discount rates of 3.97% and 3.98% will be used to calculate net periodic benefit cost beginning July 1, 2012 for the legacy Constellation pension and other postretirement benefit plans that were curtailed in the second quarter of 2012. A portion of the net periodic benefit cost is capitalized within the Consolidated Balance Sheets.

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

	Pension Benefits Three Months Ended June 30,		Other Postretirement Benefits Three Months Ended June 30,	
	2012	2011	2012	2011
Service cost	$ 74	$ 53	$ 39	$ 35
Interest cost	179	163	54	51
Expected return on assets	(253)	(234)	(29)	(28)
Amortization of:				
Transition obligation	—	—	2	3
Prior service cost (benefit)	3	3	(3)	(10)
Actuarial loss	115	82	19	17
Contractual termination benefit cost(a)	14	—	6	—
Curtailment gain	—	—	(2)	—
Net periodic benefit cost	$ 132	$ 67	$ 86	$ 68

	Pension Benefits Six Months Ended June 30,		Other Postretirement Benefits Six Months Ended June 30,	
	2012	2011	2012	2011
Service cost	$ 135	$ 106	$ 76	$ 71
Interest cost	343	325	104	103
Expected return on assets	(484)	(469)	(58)	(56)
Amortization of:				
Transition obligation	—	—	6	5
Prior service cost (benefit)	7	7	(6)	(19)
Actuarial loss	221	165	38	33
Contractual termination benefit cost(a)	14	—	6	—
Curtailment gain	—	—	(2)	—
Net periodic benefit cost	$ 236	$ 134	$ 164	$ 137

(a) As discussed above, 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, 2012 and 2011, for Generation's, ComEd's, PECO's, BGE's and BSC's allocated portion of the pension and postretirement benefit plans. These amounts include the contractual termination benefit charges and curtailment gain recognized in the second quarter of 2012.

Pension and Postretirement Benefit Costs	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Generation	$ 94	$ 61	$ 175	$ 123
ComEd	68	54	137	108
PECO	13	8	26	16
BGE(a)(b)	18	14	32	28
BSC(c)	25	12	42	24

(a) BGE's pension and postretirement benefit costs for the six months ended June 30, 2012 and 2011 include $12 million and $28 million, respectively, of costs incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012. BGE's pension and postretirement benefit costs for the three months ended June 30, 2011 include $14 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 three and six months ended June 30, 2012 and 2011 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 $83 million to its qualified pension plans in 2012, of which Generation, ComEd and PECO will contribute $51 million, $9 million, and $12 million, respectively. Legacy Constellation's 2011 pension contributions included an acceleration of estimated calendar year 2012 contributions. Therefore, BGE does not anticipate any qualified pension contributions in 2012. 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 $67 million in 2012, of which Generation, ComEd, PECO and BGE will make payments of $9 million, $14 million, $1 million and $1 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 2012, 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 $318 million in 2012, of which Generation, ComEd, PECO and BGE expect to contribute $132 million, $116 million, $34 million and $14 million, respectively. This total excludes $4 million in 2012 other postretirement benefit plan contributions by BGE prior to the closing of Exelon's merger with Constellation on March 12, 2012.

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

Plan Assets

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

Exelon has developed and implemented 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, 2012 and 2011:

Savings Plan Matching Contributions	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Exelon	$ 17	$ 15	$ 33	$ 34
Generation	8	8	15	18
ComEd	5	4	9	10
PECO	2	2	4	4
BGE(a)	2	2	4	4
BSC(b)	1	1	2	2

(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.

13. Plant Retirements (Exelon and Generation)

In 2009, Exelon announced its intention to permanently retire three coal-fired generating units and one oil/gas-fired generating unit, effective May 31, 2011, in response to the economic outlook related to the continued operation of these four units. However, PJM determined that transmission reliability upgrades would be necessary to alleviate reliability impacts and that those upgrades would be completed in a manner that will permit Generation's retirement of two of the units on May 31, 2011 and two of the units subsequent to May 31, 2011. On May 31, 2011, Cromby Generating Station (Cromby) Unit 1 and Eddystone Generating Station (Eddystone) Unit 1 were retired; Cromby Unit 2 retired on December 31, 2011 and Eddystone Unit 2 on May 31, 2012. On May 27, 2011, the FERC approved a settlement providing for a reliability-must-run rate schedule, which defines compensation to be paid to Generation for continuing to operate these units. The monthly fixed-cost recovery during the reliability-must-run period for Eddystone Unit 2 was approximately $6 million. Such revenue was intended to recover total expected operating costs, plus a return on net assets, of the unit during the reliability-must-run period. In addition, Generation was reimbursed for variable costs, including fuel, emissions costs, chemicals, auxiliary power and for project investment costs during the reliability-must-run period. Eddystone Unit 2 operated under the reliability-must-run agreement from June 1, 2011 until the May 31, 2012 retirement date. See Note 14 of the Exelon 2011 Form 10-K for additional information.

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

The following table presents the activity of severance obligations for the announced Cromby and Eddystone retirements from December 31, 2011 through June 30, 2012:

Severance Benefits Obligation	Exelon and Generation
Balance at December 31, 2011	$ 7
Cash payments	(2)
Balance at June 30, 2012	$ 5

14. 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, 2012, there were approximately 20 million shares authorized for issuance under the LTIP. For the three and six months ended June 30, 2012 and 2011, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

In connection with the acquisition of Constellation in March 2012, Exelon assumed Constellation’s 1995 Long-Term Incentive Plan, 2002 Senior Management Long-Term Incentive Plan, Amended and Restated 2007 Long-Term Incentive Plan, Amended and Restated Management Long-Term Incentive Plan and Executive Long-Term Incentive Plan (collectively and as amended, if applicable, the “Constellation Plans”). Stock-based awards granted under the Constellation Plans and held by Constellation employees were generally converted into outstanding Exelon stock-based compensation awards with the estimated fair value determined to be $71 million using the Black-Scholes model. Refer to Note 3 - Merger and Acquisitions for further information regarding the merger transaction. Specifically, as of the merger closing: (1) Exelon converted 12,037,093 outstanding shares that were subject to Constellation stock options into 11,194,151 Exelon stock options valued at $65 million; and (2) Exelon converted 165,219 Constellation no-sale restricted stock units into 153,654 Exelon no-sale restricted stock units valued at $6 million.

Exelon generally grants most of its stock options in the first quarter of each year. In connection with the merger with Constellation, the Compensation Committee of Exelon’s Board of Directors elected to delay the annual equity award grant from January 2012 to the effective date of the merger on March 12, 2012, in order to ensure that a majority of eligible employees receive grants on the same date and at the same market price.

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

The following table presents the stock-based compensation expense included in Exelon's Consolidated Statements of Operations and Comprehensive Income for the three and six months ended June 30, 2012 and 2011:

	Three Months Ended June 30,		Six Months Ended June 30,	
Components of Stock-Based Compensation Expense	2012	2011	2012	2011
Performance share awards	$ 10	$ 6	$ 26	$ 12
Stock options	4	1	11	6
Restricted stock units	11	5	30	21
Other stock-based awards	1	1	2	2
Total stock-based compensation expense included in operating and maintenance expense	26	13	69	41
Income tax benefit	(10)	(5)	(26)	(16)
Total after-tax stock-based compensation expense	$ 16	$ 8	$ 43	$ 25

The following table presents stock-based compensation expense for the three and six months ended June 30, 2012 and 2011:

	Three Months Ended June 30,		Six Months Ended June 30,	
Subsidiaries	2012	2011	2012	2011
Generation	$ 9	$ 5	$ 24	$ 19
ComEd	2	1	7	3
PECO	1	1	3	3
BGE(a)	1	—	3	—
BSC(b)	13	6	32	16
Total	$ 26	$ 13	$ 69	$ 41

(a) BGE's stock-based compensation expense 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. BGE's stock-based compensation expense for the three and six months ended June 30, 2011 was $1 million and $6 million, respectively.
(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.

There were no significant stock-based compensation costs capitalized during the three and six months ended June 30, 2012 and 2011.

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.

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

The following table presents the weighted average assumptions used to value Exelon stock options at their grant date for the three and six months ended June 30, 2012 and 2011:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Dividend yield	5.28%	4.84%	5.28%	4.84%
Expected volatility	23.20%	24.40%	23.20%	24.40%
Risk-free interest rate	1.30%	2.65%	1.30%	2.65%
Expected life (years)	6.25	6.25	6.25	6.25

The assumptions above relate to Exelon stock options granted during the period and therefore do not include stock options that were converted in connection with the merger with Constellation during the six months ended June 30, 2012.

The following table summarizes Exelon's stock option activity for the six months ended June 30, 2012:

	Shares	Weighted Average Exercise Price (per share)
Balance of shares outstanding at December 31, 2011	11,553,761	$ 48.49
Granted	2,372,000	39.66
Converted Constellation options	11,194,151	41.35
Exercised	(1,149,913)	25.98
Forfeited	(37,475)	46.94
Expired	(94,867)	47.08
Balance of shares outstanding at June 30, 2012	23,837,657	$ 45.35
Exercisable at June 30, 2012(a)	21,393,180	$ 45.87

(a) Includes stock options issued to retirement eligible employees.

The following table summarizes Exelon's nonvested stock option activity for the six months ended June 30, 2012:

	Shares	Weighted Average Exercise Price (per share)
Nonvested at December 31, 2011(a)	877,050	$ 48.66
Granted(b)	2,372,000	39.66
Converted Constellation options	11,194,151	41.35
Vested(b)(c)	(11,903,857)	41.66
Forfeited	(94,867)	47.08
Nonvested at June 30, 2012(a)	2,444,477	$ 40.60

(a) Excludes 2,594,061 and 1,348,000 of stock options issued to retirement-eligible employees as of June 30, 2012 and December 31, 2011, respectively, as they are fully vested.
(b) Includes 8,684,709 of converted Constellation options that were vested prior to the Merger on March 12, 2012.
(c) Includes 1,599,000 of stock options issued to retirement-eligible employees in 2012 that vested immediately upon the employee reaching retirement eligibility.

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

At June 30, 2012, $10 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of 2.7 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.

The following table summarizes Exelon's nonvested restricted stock unit activity for the six months ended June 30, 2012:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2011(a)	1,074,484	$ 48.08
Granted	1,087,572	40.03
Converted Constellation restricted stock	825,735	38.91
Vested	(317,940)	43.60
Forfeited	(32,829)	43.71
Undistributed vested awards(b)	(550,253)	40.42
Nonvested at June 30, 2012(a)	2,086,769	$ 42.57

(a) Excludes 624,159 and 448,827 of restricted stock units issued to retirement-eligible employees as of June 30, 2012 and December 31, 2011, respectively, as they are fully vested
(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2012.

At June 30, 2012, Exelon had obligations related to outstanding restricted stock units not yet settled of $54 million, which are included in common stock in Exelon's Consolidated Balance Sheets. In addition, Exelon had obligations related to outstanding restricted stock units that will be settled in cash of $1 million at June 30, 2012, which are included in deferred credits and other liabilities in Exelon's Consolidated Balance Sheets. During the three months ended June 30, 2012 and 2011, Exelon settled restricted stock units with a fair value totaling $2 million and $2 million, respectively. During the six months ended June 30, 2012 and 2011, Exelon settled restricted stock units with a fair value totaling $21 million and $17 million, respectively. At June 30, 2012, $64 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.31 years.

Performance Share Awards

Performance share awards are granted under the LTIP with the 2012 performance share awards being settled in 50% common stock and 50% cash over the three-year vesting term. The 2011 performance share awards are being settled entirely in common stock over the three-year vesting term. The performance shares granted prior to 2011 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.

These 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.

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

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

The following table summarizes Exelon's nonvested performance share awards activity for the six months ended June 30, 2012:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2011(a)	346,848	$ 45.37
Granted	1,248,005	39.73
Vested	(155,447)	47.76
Forfeited	(6,015)	41.06
Undistributed vested awards(b)	(203,512)	40.22
Nonvested at June 30, 2012(a)	1,229,879	$ 40.21

(a) Excludes 270,366 and 455,418 of performance share awards issued to retirement-eligible employees as of June 30, 2012 and December 31, 2011, respectively, as they are fully vested.
(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2012.

During the three months ended June 30, 2012 and 2011, the fair value of Exelon's settled performance shares and payments made in cash were immaterial. During the six months ended June 30, 2012 and 2011, Exelon settled performance shares with a fair value totaling $19 million and $21 million, respectively, of which $3 million and $10 million was paid in cash, respectively. As of June 30, 2012, $29 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.

15. Earnings Per Share and Equity (Exelon)

Earnings per Share

Diluted earnings per share is calculated by dividing net income 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,		Six Months Ended June 30,	
	2012	2011	2012	2011
Net income on common stock	$ 286	$ 620	$ 486	$ 1,288
Average common shares outstanding — basic	853	663	779	663
Assumed exercise of stock options, performance share awards and restricted stock	3	1	2	1
Average common shares outstanding — diluted	856	664	781	664

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 13 million for the three and six months ended June 30, 2012, respectively, and 10 million and 9 million for the three and six months ended June 30, 2011, 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, 2012. In 2008, Exelon management decided to defer indefinitely any share repurchases.

16. 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 18 of the Exelon 2011 Form 10-K and Note 12 of Constellation's and BGE's 2011 Form 10-K.

Commitments

Energy Commitments

As of June 30, 2012, Generation's short- and long-term commitments relating to the 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
2012	$ 255	$ 32	$ 18	$ 460	$ 765
2013	363	81	32	653	1,129
2014	352	45	26	411	834
2015	350	12	13	—	375
2016	264	5	2	—	271
Thereafter	664	6	36	—	706
Total	$ 2,248	$ 181	$ 127	$ 1,524	$ 4,080

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

(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, 2012, 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. 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.

As part of reaching a comprehensive agreement with EDF in October 2010, the existing power purchase agreement with CENG was modified to be unit-contingent through the end of its original term in 2014. 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 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. Further, while CENG purchases from the balance sheet date through December 31, 2014 will eventually be purchased at a fixed price, only those portions of purchases that have been locked in with a fixed price have been disclosed in the table. Generation continues to own a 50.01% membership interest in CENG that is accounted for as an equity method investment. See Note 5 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, 2012 are as follows:

		Expiration within					
	Total	2012	2013	2014	2015	2016	2017 and beyond
ComEd							
Electric supply procurement(a)	$1,165	$ 62	$367	$323	$136	$137	$ 140
Renewable energy and RECs(b)	1,698	37	71	73	74	81	1,362
PECO							
Electric supply procurement(c)	1,006	491	403	87	25	—	—
AECs	39	7	11	9	2	2	8
Curtailment services	7	7	—	—	—	—	—
BGE							
Electric supply procurement(d)	1,509	509	730	270	—	—	—
Curtailment services	176	23	49	47	41	16	—

(a) ComEd entered into various contracts for the procurement of electricity that expire between 2012 and 2017. ComEd is permitted to recover its electric supply procurement costs from retail customers with no mark-up. See Note 4 — Regulatory Matters for additional information.
(b) ComEd entered into various contracts for the procurement of renewable energy and RECs that expire between 2012 and 2032. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. If events were to occur such that ComEd is not allowed to recover the costs under these contracts from retail customers, ComEd may elect to reduce the annual quantity purchased under these contracts. See Note 4 — 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 2012 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 Program. See Note 4 — Regulatory Matters for additional information.

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

(d) BGE entered into various contracts for the procurement of electricity that expire between 2012 and 2014. The cost of power under these contracts is recoverable under MDPSC approved fuel clauses. See Note 4 — Regulatory Matters for additional information.

Fuel Purchase Obligations

In addition to the energy commitments described above, Generation has commitments to purchase fuel supplies for nuclear and fossil generation (and with respect to coal, commitments to sell coal) of which a portion relate to generating stations to be divested. See Note 3 — Mergers and Acquisitions for further details. 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, 2012, these net commitments were as follows:

		Expiration within					
	Total	2012	2013	2014	2015	2016	2017 and beyond
Generation	$8,335	$674	$1,129	$1,140	$1,172	$757	$ 3,463
PECO	433	94	96	68	53	31	91
BGE	642	64	92	70	52	51	313

Other Purchase Obligations

The Registrants' other purchase obligations as of June 30, 2012, which primarily represent commitments for services, materials and information technology, are as follows:

		Expiration within					
	Total	2012	2013	2014	2015	2016	2017 and beyond
Exelon	$1,115	$534	$181	$139	$95	$30	$ 136
Generation	606	302	105	95	71	5	28
ComEd	139	87	12	6	5	5	24
PECO	101	54	19	18	1	1	8
BGE	5	3	2	—	—	—	—

Construction Commitments

Generation has committed to the construction of a solar PV facility in Los Angeles County, California. Generation's estimated commitments are $362 million and $446 million for the years 2012 and 2013, respectively. See Note 3 — Merger and Acquisitions for additional information.

Generation has committed to the construction of approximately 400 MW of new wind facilities during 2012. Generation's estimated commitments are approximately $175 million primarily related to the procurement of the turbines.

Refer to Note 4 — Regulatory Matters for information on investment programs associated with regulatory mandates, such as ComEd's Infrastructure Investment Plan under EIMA, PECO's Smart Meter Procurement and Installation Plan and BGE's comprehensive smart grid initiative.

Constellation Merger Commitments

The tables above do not include the merger commitments made to the State of Maryland in conjunction with the Constellation merger. See Note 3 — Merger and Acquisitions for additional information on the merger commitments.

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

Contingencies

Commercial Commitments

The Registrants' commercial commitments as of June 30, 2012, representing commitments potentially triggered by future events were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Letters of credit (non-debt)(a)	$ 2,437	$ 1,776	$ 23	$ 21	$ 1
Guarantees	10,409(b)	2,168(c)	208(d)	181(e)	252(f)
Nuclear insurance premiums(g)	2,098	2,098	—	—	—
Total commercial commitments	$14,944	$ 6,042	$ 231	$202	$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 $1.6 billion at June 30, 2012, which represents the total amount Exelon could be required to fund based on June 30, 2012 market prices.
(c) Primarily reflects guarantees issued to ensure performance under energy marketing and other specific contracts and $205 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 $0.5 billion at June 30, 2012, which represents the total amount Generation could be required to fund based on June 30, 2012 market prices.
(d) Primarily reflects full and unconditional guarantees of $200 million Trust Preferred Securities of ComEd Financing III.
(e) Primarily reflects full and unconditional guarantees of $178 million Trust Preferred Securities of PECO Trust III and IV.
(f) Primarily reflects full and unconditional guarantees of $250 million Trust Preferred Securities of BGE Capital Trust II.
(g) Does not include potential maximum combined retrospective premium obligations of CENG amounting to $691 million as of June 30, 2012, of which Generation's ownership interest is 50.01%.

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 was $2.1 billion at June 30, 2012, which is included above in the Commercial Commitments table and which does not include the potential maximum combined retrospective premium obligations of CENG. See the Nuclear Insurance section within Note 18 of the Exelon 2011 Form 10-K and Note 12 of Constellation's and BGE's 2011 Form 10-K for additional details on Generation's nuclear insurance premiums.

Indemnifications Related to 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).

In connection with the sale, Generation recorded liabilities related to certain indemnifications provided to Dynegy and other guarantees directly resulting from the transaction. 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, 2012 and is set to 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, 2012. Generation 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 by 2014. 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, 13 of which have been approved for cleanup by the Illinois EPA or the U.S. EPA and 27 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 and investigated 12 sites that BGE had owned. Two sites remain active and require some level of remediation under the direction of the Maryland Department of the Environment. The required remediation cost at these two remaining sites is not considered material.

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

Pursuant to orders from the ICC, PAPUC and MDPSC, respectively, ComEd, PECO and BGE are authorized to and are currently recovering environmental costs for the remediation of former MGP facility sites from customers, for which they have recorded regulatory assets. During the second quarter of 2012, ComEd completed an annual study of its future estimated MGP remediation requirements. The results of this study indicated that additional remediation would be required at certain sites; accordingly, ComEd increased its reserve and regulatory asset by $140 million. See Note 4 - Regulatory Matters for additional information regarding the associated regulatory assets.

The historical nature of the MGP sites and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs based on probabilistic and deterministic modeling using all available information at the time of each study and the remediation standards currently required by the U.S. EPA. The increase in the reserve at ComEd was predominately tied to 6 sites with a total increase of approximately $105 million. The change was driven by the completion of additional preliminary environmental investigations that identified increases in scope for the remediation of larger areas and to greater depths, along with the requirement for additional groundwater management not previously contemplated in prior studies. ComEd also obtained new information on scope requirements for several sites where another PRP is leading remediation efforts and that ComEd shares responsibility. Prior to completion of any significant clean up, each site remediation plan is approved by the Illinois EPA.

As of June 30, 2012 and December 31, 2011, 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, 2012	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 357	$ 297
Generation	51	—
ComEd	262	256
PECO	44	41

December 31, 2011	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 224	$ 168
Generation	47	—
ComEd	127	121
PECO	50	47

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

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

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

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 C.P. Crane, Clinton, Dresden, Eddystone, Fairless Hills, Gould Street, H.A. Wagner, 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. See ITEM 2. PROPERTIES of the Exelon 2011 Form 10-K and ITEM 2. PROPERTIES of the Constellation 2011 Form 10-K for a description of these facilities.

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 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 July 18, 2012, the U.S. EPA announced that it had agreed to extend the court approved Settlement Agreement to extend the deadline to issue a final rule until June 27, 2013. Until the rule is finalized, the state permitting agencies will continue to apply their best professional judgment to address impingement and entrainment.

Oyster Creek. On January 7, 2010, the NJDEP issued a draft NPDES permit for Oyster Creek that would have required, in the exercise of its best professional judgment, the installation of cooling towers as the best technology available within seven years after the effective date of the permit. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek no later than December 31, 2019. The current NRC license for Oyster Creek expires in 2029. In reliance upon Exelon’s determination to cease generation operations no later than December 31, 2019, the NJDEP determined that closed cycle cooling is not the best technology available for Oyster Creek given the length of time that would be required to retrofit from the existing once-through cooling system to a closed-cycle cooling system and the limited life span of the plant after installation of a closed-cycle cooling system. Based on its consideration of these and other factors, NJDEP determined that the existing measures at the plant represent the best technology available for the facility’s cooling water intake through cessation of generation operations.

On December 9, 2010, Generation executed an Administrative Consent Order (ACO) with the NJDEP regarding Oyster Creek. The ACO sets forth, among other things, the agreement by Generation to permanently cease generation operations at Oyster Creek if the conditions of the ACO are satisfied. In accordance with the ACO, on December 21, 2011, the NJDEP agreed to issue a final NPDES permit that became effective on April 12, 2012 that does not require the construction of cooling towers or other closed-cycle cooling facilities. The ACO and the final permit apply only to Oyster Creek based on its unique circumstances and does not set any precedent for the ultimate compliance requirements for Section 316(b) at Exelon’s other plants.

As a result of the decision and the ACO, the expected economic useful life of Oyster Creek was reduced by 10 years to correspond to Exelon's current best estimate as to the timing of ceasing generation operations at the Oyster Creek unit in 2019. The financial impacts relate primarily to accelerated depreciation and accretion expense associated with the changes in decommissioning assumptions related to Generation's asset retirement obligation over the remaining expected economic useful life of Oyster Creek.

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, the operator of Salem, 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 be approximately $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 Maryland Department of the Environment 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. Constellation recorded a liability in its Consolidated Balance Sheets of approximately $23 million to comply with the consent decree. As of June 30, 2012, approximately $18 million of these costs had been paid, resulting in a remaining liability at June 30, 2012 of $5 million.

Alleged Conemaugh Clean Streams Violation by PA DEP. The PA DEP has alleged that GenOn Northeast Management Company (GenOn), the operator of Conemaugh Generating Station (CGS), violated the Pennsylvania Clean Streams Law. GenOn has been engaged in discussions with PA DEP and has reached agreement on a proposed Consent Order that will be submitted for court approval. Under the proposed Consent Order, GenOn will be obligated to pay a civil penalty of $500,000, of which Generation's responsibility would be approximately $200,000.

Air

Cross State Air Pollution Rule. 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 6, 2010, the U.S. EPA published the proposed Transport Rule as the replacement to the CAIR. On July 7, 2011, the U.S. EPA published the final rule, now 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. The final rule maintains the January 1, 2012 and January 1, 2014 phase-in dates that were in the proposed Transport Rule. However, the CSAPR imposes tighter emissions caps than the proposed Transport Rule and includes six additional states under the summertime NO_x reduction requirements. These emissions limits may be further reduced as the U.S. EPA finalizes more restrictive ozone and particulate matter NAAQS in the 2012 — 2014 timeframe.

Under the CSAPR, Generation units will receive allowances based on historic heat input, intrastate, and limited interstate, trading of allowances is permitted, subject to certain limitations. The CSAPR restricts entirely the use of pre-2012 allowances. Existing SO_2 allowances under the ARP would remain available for use under ARP. During the third quarter of 2010, Generation recognized a lower of cost or market impairment charge of $57 million on its ARP SO_2 allowances that are not expected to be used by Generation's fossil-fuel power plants and that have not been sold forward. The impairment was recorded due to the significant decline of allowance market prices because CSAPR regulations would restrict entirely the use of ARP SO_2 allowances beginning in 2012. As of June 30, 2012, Generation had $39 million of emission allowances carried at the lower of weighted average cost or market.

On October 6, 2011 and February 7, 2012, the U.S. EPA proposed for public comment certain technical corrections to CSAPR, including correction of data errors in determining generation unit allowances and state allowance budgets. These corrections will increase the number of emission allowances available under the CSAPR. In addition, the proposal defers until 2014 penalties that will involve surrender of additional allowances should states not meet certain levels of emission reductions. This deferral is intended to increase the liquidity of allowances during the initial years of transition from CAIR to the CSAPR. On June 12, 2012, U.S. EPA issued its final technical corrections and associated updates to state emission budgets, and generating unit emission allowance allocations. On a related matter, on May 30, 2012, U.S. EPA issued its final rule with regard to electric generating unit regulation under the regional haze program. Under this final rule, states participating in the CSAPR trading programs will be allowed to use those programs in place of source-specific BART for sulfur dioxide and/or nitrogen oxide emissions from power plants that are subject to the regional haze rule

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. The D.C. Circuit Court granted permission for Exelon, as well as a number of other parties, to intervene in the litigation in support of the rule. 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. Subsequently the Court ordered an expedited case management schedule that resulted in oral argument on April 13, 2012. It is unknown when the Court will issue its decision on the merits. Exelon believes that the CSAPR is a valid exercise of the U.S. EPA's authority and discretion under the Clean Air Act.

EPA Mercury and Air Toxics Standards (MATS). On April 16, 2012, the MATS rule to reduce emissions of toxic air pollutants from electric generating units (EGUs) became final. The MATS rule also finalized the new source performance standards for EGUs. The MATS rule resulted from a finding by the D.C. Circuit Court that the prior rule, known as the Clean Air Mercury Rule (CAMR), was invalid because it did not regulate mercury as a HAP. 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 cause 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.

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, Generation owns three base-load, coal-fired generation units in Maryland that were acquired in the merger with Constellation — Brandon Shores, H.A. Wagner and C.P. Crane. However, in connection with certain of the regulatory approvals required for the merger, Exelon agreed to divest these generating stations. It is anticipated that these plants are well positioned to comply with CSAPR and MATS, since Maryland has adopted SO_2, NO_x, and mercury emission limits under its Healthy Air Act and Clean Power Rule that are generally consistent with the requirements of CSAPR and MATS.

In addition, as of June 30, 2012, Exelon had a $670 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, 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.

NAAQS. The U.S. EPA previously announced that it would complete a review of NAAQS in the 2011 — 2012 timeframe for particulate matter, nitrogen dioxide, sulfur dioxide, and lead. This review could result in more stringent emissions limits on fossil-fired electric generating stations. In July 2012, the D.C. Circuit Court issued separate rulings upholding tightened NAAQs established by the U.S. EPA in 2010 for nitrogen dioxide and sulfur dioxide. The rulings clear the way for the U.S. EPA to continue work already underway with state and local agencies on implementing revised SIP's designed to achieve or maintain the required air quality levels. To the extent not already impacted by CSAPR and MATS, some power plants could be required to achieve further reductions of nitrogen dioxide and sulfur dioxide emissions.

In September 2011, the U.S. EPA withdrew its reconsideration of the NAAQS standard for ozone, which is next scheduled for reconsideration in 2013. On June 14, 2012, the U.S. EPA proposed revisions to the Agency's particulate matter NAAQS and indicated that it would issue a final rule by December 14, 2012. In its proposed rule, the U.S. EPA has requested public comment on a lowered annual PM2.5 standard, as well as proposed a new secondary NAAQS to improve urban visibility. The U.S. EPA indicates that by 2020 it expects most areas of the country will be in attainment of the new NAAQS based on currently expected regulations, such as the CSAPR and MATS regulations, among others.

Notices and Finding of Violations Related to Electric Generation Stations. On August 6, 2007, ComEd received a NOV, addressed to it and Midwest Generation, LLC (Midwest Generation) from the U.S. EPA, alleging that ComEd and Midwest Generation have violated and are continuing to violate several 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 1999.

The generating stations are currently owned and operated by Midwest Generation, which purchased the stations in December 1999 from ComEd. Under the terms of the sale agreement, Midwest Generation and its affiliate, Edison Mission Energy (EME), assumed responsibility for environmental liabilities associated with the ownership, occupancy, use and operation of the stations, including responsibility for compliance of the stations with environmental laws before the purchase of the stations 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 August 2009, the DOJ and the Illinois Attorney General filed a complaint against Midwest Generation with the U.S. District Court for the Northern District of Illinois initiating enforcement proceedings with respect to the alleged Clean Air Act violations set forth in the NOV. Neither ComEd nor Exelon were 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 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 substantially similar to 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 U.S. District Court granted ComEd's motion to dismiss the May 2010 complaint. On January 3, 2012, upon leave of the U.S. District Court, the government parties appealed the dismissal of ComEd to the U.S. Circuit Court of Appeals.

In connection with Exelon's 2001 corporate restructuring, Generation assumed ComEd's rights and obligations with respect to its former generation business. Exelon, Generation and ComEd are unable to predict the ultimate resolution of the claims alleged in the amended complaint, the costs that might be incurred or the amount of indemnity that may be available from Midwest Generation and EME; however, Exelon, Generation and ComEd have concluded that, in light of the District Court decision the likelihood of loss is remote. Therefore, no reserve has been established. Further, Generation believes, that it would be reimbursed by Midwest Generation and EME for any losses under the terms of the indemnification agreement, subject to the credit worthiness of Midwest Generation and EME. On July 31, 2012, Edison International (EI), the parent company of EME, stated that EME may not have sufficient liquidity to repay unsecured debt due in June 2013. Furthermore, EI stated that should EME be unable to restructure its debt, it would need to reorganize under the U.S. Bankruptcy Code. In that event, ComEd and Generation would be an unsecured creditor with respect to any indemnification obligations owed by EME and Midwest Generation.

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 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 SFS that could take up to one year to complete, and 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. An 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 the use of an 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 $100 million. The DOJ and the PRPs have agreed to toll the statute of limitations until August 2012 so that settlement discussions can proceed. It is likely that the parties will agree to extend the statute of limitations until August 2013. 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"). 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 and the motions are still before the Court. Exelon remains potentially liable due to its indemnification responsibilities of Cotter described above. Due to the early stage of the litigation, Exelon is unable to determine the extent of its potential liability, 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 2012. Since the U.S. EPA has not selected the remedy and the allocation of the clean-up costs among the PRPs has not been determined, an estimate of the range of BGE's possible loss, if any, cannot be determined. 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. The letter provided 60 days for the PRPs to decide whether or not to participate in the investigation. 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 July 30, 2012, BGE along with the three other named PRP's provided the U.S. EPA with a "Good Faith Offer" along with a proposed Settlement Agreement to conduct a Remedial Investigation and a Feasibility Study at the Site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The PRPs will seek to reach agreement with the U.S. EPA to conduct the investigation. 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 possible loss, if any, cannot be determined.

Climate Change Regulation. Exelon is subject to climate change regulation or legislation at the international, 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 June 26, 2012, the United States Court of Appeals for the District of Columbia, in a per curiam 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.

On April 13, 2012, the U.S. EPA published proposed regulations for new source performance standards (NSPS) for GHG emissions from new fossil-fueled power plants, greater than 25 MW, that would require the plants to limit CO_2 emissions to a thirty-year average of less than 1000 pounds per MWh (less than 1800 pounds per MWh for the first ten years and less than 600 pounds per MWh thereafter). 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.

Litigation and Regulatory Matters

Except to the extent noted below, the circumstances set forth in Note 18 of the Exelon 2011 Form 10-K and Note 12 of Constellation's and BGE's 2011 Form 10-K describe, in all material respects, the current status of litigation matters. The following is an update to that discussion.

Asbestos Personal Injury Claims (Exelon, Generation and BGE)

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

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

At June 30, 2012 and December 31, 2011, Generation had reserved approximately $65 million and $49 million, respectively, in total for asbestos-related bodily injury claims. As of June 30, 2012, approximately $13 million of this amount related to 167 open claims presented to Generation, while the remaining $52 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary. During the three months ended June 30, 2012, Generation increased its reserve by approximately $19 million, primarily due to increased actual and projected number and severity of claims.

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

Approximately 480 individuals who were never employees of BGE or Generation 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 Generation in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or Generation 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 once they are placed on the trial docket. At present, none of the pending cases are set for trial. Given the limited discovery, BGE and Generation do not know the specific facts that are necessary to provide an estimate of the possible loss relating to these claims. 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.

Gain on U.S. Department of Energy Settlements (Exelon and Generation)

CENG is currently in negotiations with the DOE to recover damages caused by the DOE’s failure to comply with legal and contractual obligations to dispose of spent nuclear fuel related to the Nine Mile Point nuclear power plant. Any funds received from the DOE related to costs incurred prior to November 6, 2009 will belong to Generation. Generation has recorded a pre-acquisition contingent asset of approximately $25 million related to its share of the potential settlement. See Note 3 — Mergers and Acquisitions for additional information on the merger.

Federal Energy Regulatory Commission Investigation (Exelon and Generation)

On January 30, 2012, FERC published a notice on its website regarding a non-public investigation of certain of Constellation’s power trading activities in and around the New York ISO from September 2007 through December 2008. Prior to the merger, Constellation announced on March 9, 2012, that it had resolved the FERC investigation. Under the settlement, Constellation agreed to pay a $135 million civil penalty and $110 million in disgorgement. The disgorgement amount will be disbursed in two ways. First, Constellation will provide $1 million each to six U.S. regional grid operators for the purpose of improving their surveillance and analytic capabilities. The remainder of the disgorgement amount was deposited in a fund that will be administered by a FERC ALJ. State agencies in New York, New England and PJM (the regional grid operator for 13 states and the District of Columbia) will be eligible to make claims against the fund on behalf of electric energy consumers in those states.

During the six months ended June 30, 2012, Generation recorded expense of $195 million in operating and maintenance expense with the remaining $50 million recorded as a Constellation pre-acquisition contingency. As of June 30, 2012, the full amount of the civil penalty and disgorgement was paid. See Note 3 — Merger and Acquisitions for additional information on the merger.

Continuous Power Interruption (ComEd)

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"). The ICC is currently conducting a proceeding to assess ComEd's request. In the absence of a favorable determination from the ICC, some ComEd customers affected by the outages could seek recovery of their actual, non-consequential damages, and the local governments in the areas in which those customers are located could seek recovery of emergency and contingency expenses. On January 27, 2012, the ICC Staff and the Illinois Attorney General (AG) filed testimony in the ICC proceeding. They both disagreed with ComEd's interpretation that the statute does not apply to the interruptions caused by the 2011 storms. The ICC witness supported granting a waiver for three of the six storms, while the AG asserted that ComEd should be held responsible for the damages from all the storms.

A hearing in this proceeding was held on July 10-12, 2012. At the hearing, the ICC Staff witness, based on updated data provided by ComEd, now testified that ComEd should receive a waiver of liability in connection with five of the six storm systems in the Summer 2011 Storm Docket. As for the sixth storm system that struck on July 11, 2011 and affected more than 900,000 customers, the ICC Staff witness testified that 51,767 customers were affected by interruptions for which he felt a waiver should not be granted. Post-hearing briefing is underway and expected to conclude by September 13, 2012. The Administrative Law Judge has not stated when he expects to issue a proposed Order.

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 February 14, 2012, the ICC Staff and the AG filed testimony in the proceeding. ICC staff recommended that the ICC issue ComEd a waiver based on the extreme weather conditions. The AG took the same position as it had in the Summer 2011 Storm Docket noted above. A hearing on this proceeding was also held on July 10-12, 2012 and post hearing briefing is also underway. Additional active proceedings related to storms of lesser collective impact are also pending.

The ultimate outcomes of these proceedings are uncertain, and the amount of damages, if any, which might be asserted, 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 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 seek, 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 June 18, 2009, the court appointed a lead plaintiff, who filed a consolidated amended complaint on September 17, 2009. On November 17, 2009, the defendants moved to dismiss the consolidated amended complaint in its entirety. On August 13, 2010, the District Court of Maryland issued a ruling on the motion to dismiss, holding that the plaintiffs failed to state a claim with respect to the claims of the common shareholders under the Securities Exchange Act of 1934 and limiting the suit to those persons who purchased Debentures in the June 2008 offering. In August 2011, plaintiffs requested permission from the court to file a third amended complaint in an effort to attempt to revive the claims of the common shareholders. Constellation filed an objection to the plaintiffs' request for permission to file a third amended complaint and, on March 28, 2012, the District Court of Maryland denied the plaintiffs' request for permission to revive the claims of the common shareholders. Given that limited discovery has occurred, that the court has not certified any class and the plaintiffs have not quantified their potential damage claims, Exelon is unable at this time to provide an estimate of the range of possible loss relating to these proceedings or to determine the ultimate outcome of the securities class actions or their possible effect on its financial results.

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.

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

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

See Note 10 — Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

17. 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, 2012 and 2011:

Three Months Ended June 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds —					
Regulatory Agreement Units(a)	$ 50	$ 50	$ —	$ —	$ —
Non-Regulatory Agreement Units(a)	19	19	—	—	—
Net unrealized losses on decommissioning trust funds —					
Regulatory Agreement Units	(97)	(97)	—	—	—
Non-Regulatory Agreement Units	(35)	(35)	—	—	—
Net unrealized gains 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

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

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

Three Months Ended June 30, 2011	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory Agreement Units	$ 38	$ 38	$ —	$ —	$—
Non-Regulatory Agreement Units	16	16	—	—	—
Net unrealized gains on decommissioning trust funds					
Regulatory Agreement Units	28	28	—	—	—
Non-Regulatory Agreement Units	11	11	—	—	—
Net unrealized income on pledged assets					
Zion Station decommissioning	22	22	—	—	—
Regulatory offset to decommissioning trust fund-related activities(b)	(70)	(70)	—	—	—
Total decommissioning-related activities	45	45	—	—	—
Investment income	1	—	—	1	3
Long-term lease income	7	—	—	—	—
Interest income related to uncertain income tax positions	43	33	1	—	—
AFUDC — Equity	4	—	2	2	3
Other	1	(2)	1	—	—
Other, net	$ 101	$ 76	$ 4	$ 3	$ 6

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

Six Months Ended June 30, 2011	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory Agreement Units	$ 81	$ 81	$ —	$ —	$ —
Non-Regulatory Agreement Units	26	26	—	—	—
Net unrealized gains on decommissioning trust funds					
Regulatory Agreement Units	140	140	—	—	—
Non-Regulatory Agreement Units	54	54	—	—	—
Net unrealized income on pledged assets					
Zion Station decommissioning	45	45	—	—	—
Regulatory offset to decommissioning trust fund-related activities(b)	(221)	(221)	—	—	—
Total decommissioning-related activities	125	125	—	—	—
Investment income	2	—	—	2	7
Long-term lease income	14	—	—	—	—
Interest income related to uncertain income tax positions	46	33	1	1	—
AFUDC — Equity	9	—	4	6	7
Other	—	(6)	3	(1)	(1)
Other, net	$ 196	$ 152	$ 8	$ 8	$ 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 realized income taxes related to all NDT fund activity for those units. See Note 12 of the Exelon 2011 Form 10-K for additional information regarding the accounting for nuclear decommissioning.

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, 2012 and 2011:

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	14	14	—	—	—
Amortization of energy contract assets and liabilities(a)	485	532	—	—	—
Nuclear fuel(a)	419	419	—	—	—
Asset retirement obligation accretion(b)	115	115	—	—	—
Total depreciation, amortization, accretion and depletion	$ 1,895	$ 1,423	$ 300	$ 107	$ 150

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

Six Months Ended June 30, 2011	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization and accretion					
Property, plant and equipment	$ 629	$ 277	$ 248	$ 93	$113
Regulatory assets	27	—	22	5	31
Nuclear fuel(a)	355	355	—	—	—
Asset retirement obligation accretion(b)	103	103	—	—	—
Total depreciation, amortization and accretion	$1,114	$ 735	$ 270	$ 98	$144

(a) Included in purchased power and 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 and Comprehensive Income.

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	—	—
Merger-related commitments(d)	188	35	—	—	28
Severance cost	119	30	—	7	—
Equity in loss of unconsolidated subsidiaries	79	79	—	—	—
Other	(12)	8	7	6	(3)
Total other non-cash operating activities	$ 959	$ 317	$ 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)(e)	55
Other noncurrent assets and liabilities	4	(76)	(6)	(7)	14
Total changes in other assets and liabilities	$ (357)	$ (173)	$ (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	—	—	—

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

Six Months Ended June 30, 2011	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 271	$ 123	$ 108	$ 16	$ 28
Provision for uncollectible accounts	45	—	18	27	21
Stock-based compensation costs	43	—	—	—	—
Other decommissioning-related activity(a)	(35)	(35)	—	—	—
Energy-related options(b)	68	68	—	—	—
Amortization of regulatory asset related to debt costs	11	—	9	2	1
Amortization of rate stabilization deferral	—	—	—	—	25
Deferral of storm costs	—	—	—	—	(16)
Uncollectible accounts recovery, net	13	—	13	—	—
Discrete impacts from 2010 Rate Case Order(f)	(32)	—	(32)	—	—
Other	(6)	12	(1)	(1)	(5)
Total other non-cash operating activities	$ 378	$ 168	$ 115	$ 44	$ 54
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	(99)	—	(82)	(17)	(7)
Other regulatory assets and liabilities		—	(6)	2	(11)
Other current assets	(218)	(91)	(13)	(104)(e)	28
Other noncurrent assets and liabilities	68	(17)	139	11	(7)
Total changes in other assets and liabilities	$(249)	$ (108)	$ 38	$(108)	$ 3

(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 12 of the Exelon 2011 Form 10-K for additional information regarding the accounting for nuclear decommissioning.

(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.

(c) Includes the establishment of a regulatory asset, pursuant to EIMA, for the 2011 annual reconciliation in ComEd's distribution formula rate tariff. This amount was partially offset by a reduction recorded in 2012 to the regulatory asset for the 2011 annual reconciliation previously established. See Note 4 — Regulatory Matters for more information.

(d) See Note 3 — Mergers and Acquisitions for more information on merger-related commitments.

(e) Relates primarily to prepaid utility taxes.

(f) In May 2011, as a result of the 2010 Rate Case order, ComEd recorded one-time net benefits to reestablish previously expensed plant balances and to recover previously incurred costs related to Exelon's 2009 restructuring plan. See Note 4 — Regulatory Matters for more information.

DOE Smart Grid Investment Grant (Exelon, PECO and BGE). 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 $68 million, $34 million and $34 million, respectively, and reimbursements of $65 million, $46 million and $19 million, respectively, related to PECO's and BGE's DOE SGIG programs. For the six months ended June 30, 2011, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $34 million, $19 million and $15 million, respectively, and reimbursements of $54 million, $26 million and $28 million, respectively, related to PECO's and BGE's DOE SGIG programs. See Note 4 — Regulatory Matters for additional information regarding the DOE SGIG.

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

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants as of June 30, 2012 and December 31, 2011.

June 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$11,367(a)	$ 5,526(a)	$2,844	$2,731	$2,549
Accounts receivable:					
Allowance for uncollectible accounts	303	91	78	102	32

December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$10,959(b)	$ 5,313(b)	$2,750	$2,662	$2,465
Accounts receivable:					
Allowance for uncollectible accounts	199	29	78	92	38

(a) Includes accumulated amortization of nuclear fuel in the reactor core of $1,951 million.
(b) Includes accumulated amortization of nuclear fuel in the reactor core of $1,784 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 $21 million as of June 30, 2012 and December 31, 2011. 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 of the Exelon 2011 Form 10-K. The allowance for uncollectible accounts balance associated with these receivables at June 30, 2012 of $18 million consists of $1 million, $4 million and $13 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2011 of $17 million consists of $1 million, $3 million and $13 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of June 30, 2012 and December 31, 2011 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 their 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 of the Exelon 2011 Form 10-K.

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

Accumulated Other Comprehensive Income (Loss)

The following tables provide information about accumulated OCI (loss) recorded (after tax) within the Consolidated Balance Sheets of the Registrants as of June 30, 2012 and December 31, 2011:

June 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Accumulated other comprehensive income (loss)					
Net unrealized gain on cash flow hedges	$ 547	$ 901	$ —	$ —	$—
Pension and non-pension postretirement benefit plans	(2,864)	—	—	—	—
Net unrealized losses on foreign currency translation	(2)	(2)	—	—	—
Other comprehensive income — equity investment in CENG	6	6	—	—	—
Unrealized gain (loss) on marketable securities	—	(1)	—	1	—
Total accumulated other comprehensive income (loss)	$(2,313)	$ 904	$ —	$ 1	$—

December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Accumulated other comprehensive income (loss)					
Net unrealized gain on cash flow hedges	$ 488	$ 915	$ —	$ —	$—
Pension and non-pension postretirement benefit plans	(2,938)	—	—	—	—
Unrealized loss on marketable securities	—	—	(1)	—	—
Total accumulated other comprehensive income (loss)	$(2,450)	$ 915	$ (1)	$ —	$—

18. 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 an aggregate of 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 Independent System Operator (ISO) / Regional Transmission Operator (RTO) and/or North American Electric Reliability Corporation (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.

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

- 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 Florida Reliability Coordinating Council (FRCC) and the remaining portions of the SERC Reliability Corporation (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 Southwest Power Pool (SPP), covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the Western Electric Coordinating Council (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 Alberta Electric Systems Operator (AESO), Ontario Independent Electricity System Operator (OIESO) and the Canadian portion of MISO.

Exelon and Generation do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these regional reportable segments. 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 internally generated energy 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, the design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems, are not allocated to regions. Further, Generation's compensation under the reliability-must-run rate schedule, results of operations from the clean-coal assets held for sale; Brandon Shores, Wagner, and C.P. Crane, and other miscellaneous revenues, mark-to-market impact of economic hedging activities, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger are also not allocated to a region.

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

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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, 2012 and 2011 is as follows:

Three Months Ended June 30, 2012 and 2011

	Generation(a)	ComEd	PECO	BGE	Other(b)	Intersegment Eliminations	Exelon
Total revenues(c):							
2012	$ 3,753	$ 1,281	$ 715	$ 616	$ 363	$ (774)	$ 5,954
2011	2,455	1,444	842	—	187	(432)	4,496
Intersegment revenues(d):							
2012	$ 408	$ 1	$ 1	$ 2	$ 362	$ (774)	$ —
2011	246	—	—	—	186	(432)	—
Net income (loss):							
2012	$ 165	$ 42	$ 80	$ 16	$ (14)	$ —	$ 289
2011	443	114	83	—	(19)	—	621
Total assets:							
June 30, 2012	$ 41,087	$22,585	$9,204	$7,200	$10,163	$ (12,805)	$77,434
December 31, 2011	27,433	22,638	9,156	—	6,162	(10,394)	54,995

(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, 2012 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. For the three months ended June 30, 2011 intersegment revenues for Generation include revenue from sales to PECO of $118 million in the Mid-Atlantic region, and sales to ComEd of $128 million in the Midwest region.
(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, 2012 and 2011, utility taxes of $19 million and $7 million, respectively, are included in revenues and expenses for Generation. For the three months ended June 30, 2012 and 2011, utility taxes of $54 million and $57 million, respectively, are included in revenues and expenses for ComEd. For the three months ended June 30, 2012 and 2011, utility taxes of $34 million and $42 million, respectively, are included in revenues and expenses for PECO. For the three months ended June 30, 2012, utility taxes of $19 million are included in revenues and expenses for BGE.
(d) 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 2 of the Exelon 2011 Form 10-K for additional information on AECs. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations.

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

Generation total revenues:

	2012			2011		
	Revenues from external customers(a)	Intersegment revenues	Total Revenues	Revenues from external customers(a)	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 1,433	$ (28)	$ 1,405	$ 994	$ —	$ 994
Midwest	1,193	8	1,201	1,339	—	1,339
New England	296	32	328	3	—	3
New York	166	(22)	144	—	—	—
ERCOT	412	1	413	101	—	101
Other Regions(b)	219	25	244	53	—	53
Total Revenues for Reportable Segments	$ 3,719	$ 16	$ 3,735	$ 2,490	$ —	$ 2,490
Other(c)	34	(13)	21	(35)	—	(35)
Total Generation Consolidated Operating Revenues	$ 3,753	$ 3	$ 3,756	$ 2,455	$ —	$ 2,455

(a) Includes all wholesale and retail electric 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 and includes retail and wholesale gas, upstream natural gas, proprietary trading, demand response, energy efficiency, the design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities, home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems, mark-to-market activities associated with Generation's economic hedging activities. In addition, includes generation under the reliability-must-run rate schedule and generation of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities planned for divestiture as a result of the Exelon and Constellation merger. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date.

Generation total revenues net of purchased power and fuel expense:

	2012			2011		
	RNF from external customers(a)	Intersegment RNF	Total RNF	RNF from external customers(a)	Intersegment RNF	Total RNF
Mid-Atlantic	$ 911	$ (28)	$ 883	$ 819	$ —	$ 819
Midwest	756	8	764	887	—	887
New England	28	32	60	2	—	2
New York	61	(22)	39	—	—	—
ERCOT	118	1	119	(14)	—	(14)
Other Regions(b)	9	25	34	3	—	3
Total Revenues net of purchased power and fuel expense for Reportable Segments	$ 1,883	$ 16	$1,899	$ 1,697	$ —	$1,697
Other(c)	18	(16)	2	(83)	—	(83)
Total Generation Revenues net of purchased power and fuel expense	$ 1,901	$ —	$1,901	$ 1,614	$ —	$1,614

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

(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 and includes retail and wholesale gas, upstream natural gas, proprietary trading, demand response, energy efficiency, the design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities, home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems, mark-to-market activities associated with Generation's economic hedging activities. In addition, includes generation under the reliability-must-run rate schedule and generation of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities planned for divestiture as a result of the Exelon and Constellation merger. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date.

Six Months Ended June 30, 2012 and 2011

	Generation(a)	ComEd	PECO	BGE(b)	Other(c)	Intersegment Eliminations	Exelon
Total revenues(d):							
2012	$ 6,492	$2,670	$1,590	$ 668	$ 714	$ (1,494)	$10,640
2011	5,098	2,910	1,996	—	373	(926)	9,451
Intersegment revenues(e):							
2012	$ 774	$ 1	$ 2	$ 3	$ 715	$ (1,494)	$ 1
2011	552	1	2	—	373	(926)	2
Net income (loss):							
2012	$ 332	$ 129	$ 177	$ (50)	$ (98)	$ —	$ 490
2011	938	183	210	—	(43)	—	1,288

(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, 2012 include revenue from sales to PECO of $235 million 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. For the six months ended June 30, 2011 intersegment revenues for Generation include revenue from sales to PECO of $261 million in the Mid-Atlantic region, and sales to ComEd of $291 million in the Midwest region.
(b) Amounts represent activity recorded at BGE from March 12, 2012, the closing date of the merger, through June 30, 2012.
(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, 2012 and 2011, utility taxes of $32 million and $13 million, respectively, are included in revenues and expenses for Generation. For the six months ended June 30, 2012 and 2011, utility taxes of $115 million and $121 million, respectively, are included in revenues and expenses for ComEd. For the six months ended June 30, 2012 and 2011, utility taxes of $68 million and $90 million, respectively, are included in revenues and expenses for PECO. For the period of March 12, 2012 through June 30, 2012, utility taxes of $22 million 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 2 of the Exelon 2011 Form 10-K for additional information on AECs. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations.

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

Generation total revenues:

	2012			2011		
	Revenues from external customers(a)	Intersegment revenues	Total Revenues	Revenues from external customers(a)	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 2,404	$ (33)	$ 2,371	$ 2,070	$ —	$ 2,070
Midwest	2,407	12	2,419	2,766	—	2,766
New England	386	35	421	6	—	6
New York	211	(24)	187	—	—	—
ERCOT	541	—	541	200	—	200
Other Regions(b)	294	29	323	92	—	92
Total Revenues for Reportable Segments	$ 6,243	$ 19	$ 6,262	$ 5,134	$ —	$ 5,134
Other(c)	249	(16)	233	(36)	—	(36)
Total Generation Consolidated Operating Revenues	$ 6,492	$ 3	$ 6,495	$ 5,098	$ —	$ 5,098

(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 and includes retail and wholesale gas, upstream natural gas, proprietary trading, demand response, energy efficiency, the design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities, home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems, mark-to-market activities associated with Generation's economic hedging activities. In addition, includes generation under the reliability-must-run rate schedule and generation of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities planned for divestiture as a result of the Exelon and Constellation merger. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date.

Generation total revenues net of purchased power and fuel expense:

	2012			2011		
	RNF from external customers(a)	Intersegment RNF	Total RNF	RNF from external customers(a)	Intersegment RNF	Total RNF
Mid-Atlantic	$ 1,686	$ (33)	$ 1,653	$ 1,732	$ —	$ 1,732
Midwest	1,569	12	1,581	1,851	—	1,851
New England	64	35	99	5	—	5
New York	71	(24)	47	—	—	—
ERCOT	153	—	153	(9)	—	(9)
Other Regions(b)	19	29	48	(5)	—	(5)
Total Revenues net of purchased power and fuel expense for Reportable Segments	$ 3,562	$ 19	$ 3,581	$ 3,574	$ —	$ 3,574
Other(c)	34	(19)	15	(200)	—	(200)
Total Generation Revenues net of purchased power and fuel expense	$ 3,596	$ —	$ 3,596	$ 3,374	$ —	$ 3,374

(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 and includes retail and wholesale gas, upstream natural gas, proprietary trading, demand response, energy efficiency, the design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities, home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems, mark-to-market activities associated with Generation's economic hedging activities. In addition, includes generation under the reliability-must-run rate schedule and generation of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities planned for divestiture as a result of the Exelon and Constellation merger. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date.

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

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

EXELON CORPORATION

General

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

- *Generation*, whose business consists of owned, contracted and investments in electric generating facilities and wholesale and retail customer supply of electric and natural gas products and services, including renewable energy products, risk management services and 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 18 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 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 other than itself.

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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, 2012 compared to the same period in 2011. The 2012 financial results only include the operations of Constellation and BGE from the date of the merger with Constellation (the Merger), 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, 2012						2011	Favorable (Unfavorable)
	Generation	ComEd	PECO	BGE	Other	Exelon	Exelon	Variance
Operating revenues	$ 3,753	$1,281	$715	$616	$(411)	$5,954	$4,496	$ 1,458
Purchased power and fuel	1,852	587	296	285	(414)	2,606	1,716	(890)
Revenue net of purchased power and fuel(a)	1,901	694	419	331	3	3,348	2,780	568
Other operating expenses								
Operating and maintenance	1,166	331	172	161	(1)	1,829	1,226	(603)
Depreciation and amortization	204	152	54	71	13	494	329	(165)
Taxes other than income	90	69	42	47	6	254	191	(63)
Total other operating expenses	1,460	552	268	279	18	2,577	1,746	(831)
Equity in loss of unconsolidated affiliates	(57)	—	—	—	—	(57)	—	(57)
Operating income (loss)	384	142	151	52	(15)	714	1,034	(320)
Other income and (deductions)								
Interest expense, net	(85)	(74)	(31)	(34)	(32)	(256)	(182)	(74)
Other, net	(76)	3	2	7	21	(43)	101	(144)
Total other income and (deductions)	(161)	(71)	(29)	(27)	(11)	(299)	(81)	(218)
Income (loss) before income taxes	223	71	122	25	(26)	415	953	(538)
Income taxes	58	29	42	9	(12)	126	332	206
Net income (loss)	165	42	80	16	(14)	289	621	(332)
Net (loss) attributable to noncontrolling interests, preferred security dividends and preference stock dividends	(1)	—	1	3	—	3	1	(2)
Net income (loss) on common stock	$ 166	$ 42	$ 79	$ 13	$ (14)	$ 286	$ 620	$ (334)

	Six Months Ended June 30, 2012						2011	Favorable (Unfavorable) Variance
	Generation	ComEd	PECO	BGE	Other	Exelon	Exelon	
Operating revenues	$ 6,492	$2,670	$1,590	$668	$(780)	$10,640	$9,451	$ 1,189
Purchased power and fuel	2,896	1,208	707	352	(792)	4,371	3,716	(655)
Revenue net of purchased power and fuel(a)	3,596	1,462	883	316	12	6,269	5,735	534
Other operating expenses								
Operating and maintenance	2,340	650	375	222	206	3,793	2,449	(1,344)
Depreciation and amortization	357	300	107	90	22	876	656	(220)
Taxes other than income	164	144	74	57	9	448	394	(54)
Total other operating expenses	2,861	1,094	556	369	237	5,117	3,499	(1,618)
Equity in loss of unconsolidated affiliates	(79)	—	—	—	—	(79)	—	(79)
Operating income (loss)	656	368	327	(53)	(225)	1,073	2,236	(1,163)
Other income and (deductions)								
Interest expense, net	(138)	(156)	(62)	(42)	(53)	(451)	(363)	(88)
Other, net	103	7	5	8	29	152	196	(44)
Total other income and (deductions)	(35)	(149)	(57)	(34)	(24)	(299)	(167)	(132)
Income (loss) before income taxes	621	219	270	(87)	(249)	774	2,069	(1,295)
Income taxes	289	90	93	(38)	(150)	284	779	495
Net income (loss)	332	129	177	(49)	(99)	490	1,290	(800)
Net (loss) attributable to noncontrolling interests, preferred security dividends and preference stock dividends	(2)	—	2	4	—	4	2	(2)
Net income (loss) on common stock	$ 334	$ 129	$ 175	$ (53)	$ (99)	$ 486	$1,288	$ (802)

(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, 2012 Compared to Three Months Ended June 30, 2011. Exelon's net income was $286 million for the three months ended June 30, 2012 as compared to $620 million for the three months ended June 30, 2011, and diluted earnings per average common share were $0.33 for the three months ended June 30, 2012 as compared to $0.93 for the three months ended June 30, 2011.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $568 million primarily due to the addition of BGE's and Constellation's financial results. BGE's operating revenue net of purchased power and fuel expense was $331 million for the three months ended June 30, 2012. Generation's operating revenue net of purchased power and fuel expense increased by $287 million, of which $261 million related to the New England, New York, ERCOT and Other Regions. These regions were not previously significant contributors to Generation's revenue net of purchased power and fuel expense prior to the Merger. Generation's results were also favorably impacted by $174 million of other activities, including retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities, and by $64 million in the Mid-Atlantic region also due to the addition of Constellation's operations in 2012. Generation had mark-to-market gains of $204 million in 2012 from economic hedging activities, net of intercompany eliminations, compared to $124 million in mark-to-market losses in 2011. Offsetting these favorable impacts, Generation incurred $412 million of amortization expense for the acquired energy contracts, net, recorded at fair value at the merger date. Also, revenues net of purchased power and fuel expense decreased by $123 million in the Midwest region due to lower realized power prices, lower capacity revenues and increased nuclear fuel costs.

ComEd's revenues net of purchased power and fuel expense decreased by $34 million primarily due to the discrete impacts of the 2012 distribution rate case order, partially offset by the cost recovery for regulatory required programs, favorable weather and higher electric distribution rates effective, June 1, 2011. PECO's operating revenues net of purchased power and fuel expense decreased by $15 million primarily as a result of unfavorable weather.

Operating and maintenance expense increased by $603 million primarily due to the addition of BGE and Constellation. Labor, other benefits, contracting and materials increased by $436 million, pension and OPEB expense increased by $63 million and transaction costs and employee-related expenses increased by $32 million. In addition, ComEd's operating and maintenance expense increased by $32 million as a result of the discrete impacts in 2011 from the 2010 Rate Case Order and by $23 million related to regulatory required programs.

Depreciation and amortization expense increased by $165 million primarily due to higher plant balances resulting from the addition of BGE's and Constellation's plant balances as well as ongoing capital expenditures at Generation, ComEd and PECO.

Equity in losses of unconsolidated affiliates was $57 million primarily due to the amortization of acquired energy contracts, net, and the basis difference of Generation's ownership interest in CENG recorded at fair value at the merger date.

Interest expense increased by $74 million due to an increase in debt obligations as a result of the Merger.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011. Exelon's net income was $486 million for the six months ended June 30, 2012 as compared to $1,288 million for the six months ended June 30, 2011, and diluted earnings per average common share were $0.62 for the six months ended June 30, 2012 as compared to $1.94 for the six months ended June 30, 2011. Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $534 million primarily due to the addition of Constellation's and BGE's financial results. BGE's operating revenue net of purchased power and fuel expense was $316 million for the six months ended, June 30, 2012, which included the $113 million impact of the residential customer rate credit in connection with the Merger. Generation's operating revenue net of purchased power and fuel expense increased by $222 million, of which $356 million related to the New England, New York, ERCOT and Other Regions. These regions were not previously significant contributors to Generation's revenue net of purchased power and fuel expense prior to the Merger. Generation's results were also favorably impacted by $228 million of other activities, including retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities. Generation had mark-to-market gains of $275 million in 2012 from economic hedging activities, net of intercompany eliminations, compared to $272 million in mark-to-market losses in 2011. Offsetting these favorable impacts, Generation incurred $534 million of amortization expense for the acquired energy contracts, net, recorded at fair value at the merger date. Also, revenue net of purchased power and fuel expenses decreased by $270 million and $79 million in the Midwest and Mid-Atlantic regions, respectively, due to lower realized power prices, lower capacity revenues and increased nuclear fuel costs.

ComEd's revenues net of purchased power and fuel expense increased by $57 million primarily due to the cost recovery for regulatory required programs and higher electric distribution rates effective, June 1, 2011, partially offset by the discrete impacts of the 2012 distribution rate case order. PECO's operating revenues net of purchased power and fuel expense decreased by $71 million primarily as a result of unfavorable weather.

Operating and maintenance expense increased by $1,344 million primarily due to the addition of BGE and Constellation. Labor, other benefits, contracting and materials increased by $554 million, transaction costs and employee-related expenses increased by $176 million, and pension and OPEB expense increased by $94 million. In addition, Exelon incurred $218 million in costs incurred as part of the Maryland order approving the Merger and costs of $195 million associated with a settlement with the FERC in March, 2012. ComEd's operating and maintenance expense increased by $32 million as a result of the discrete impacts in 2011 from the 2010 Rate Case Order and by $41 million related to regulatory required programs.

Depreciation and amortization expense increased by $220 million primarily due to higher plant balances resulting from the addition of BGE's and Constellation's plant balances as well as ongoing capital expenditures at Generation, ComEd and PECO.

Equity in losses of unconsolidated affiliates was $79 million primarily due to the amortization of acquired energy contracts, net, and the basis difference of Generation's ownership interest in CENG recorded at fair value at the merger date.

Interest expense increased by $88 million due to an increase in debt obligations as a result of the Merger.

Exelon's results for the six months ended June 30, 2011 were favorably affected by certain income tax-related matters. In 2012, Exelon recorded a $121 million (after tax) non-cash benefit to income tax expense as a result of a change in state deferred tax rates resulting from a reassessment of anticipated apportionment of Exelon's deferred taxes due to the merger. Exelon's results were also favorably affected by a 2011 non-cash charge of $29 million (after tax) recorded for the remeasurement of deferred taxes at higher corporate tax rates pursuant to the Illinois tax rate change legislation and for the updated long-term state tax apportionment.

For further detail regarding the financial results for the three and six months ended June 30, 2012, 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, 2012 were $522 million, or $0.61 per diluted share, compared with adjusted (non-GAAP) operating earnings of $697 million, or $1.05 per diluted share, for the same period in 2011. Exelon's adjusted (non-GAAP) operating earnings for the six months ended June 30, 2012 were $1,125 million, or $1.44 per diluted share, compared with adjusted (non-GAAP) operating earnings of $1,476 million, or $2.22 per diluted share, for the same period in 2011. In addition to net income, 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 as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the three and six months ended June 30, 2012 as compared to the same period in 2011:

	Three Months Ended June 30,			
	2012		2011	
(All amounts after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income	$ 286	$ 0.33	$ 620	$ 0.93
Mark-to-Market Impact of Economic Hedging Activities(a)	(123)	(0.15)	75	0.12
Unrealized (Gains) Losses Related to NDT Fund Investments(b)	19	0.02	(6)	(0.01)
Plant Retirement and Divestitures(c)	(1)	—	10	0.02
Constellation Merger and Integration Costs(d)	67	0.08	15	0.02
Amortization of Acquired Contracts(e)	281	0.33	—	—
Amortization of the Fair Value of Certain Debt(f)	(3)	—	—	—
Non-Cash Benefit Resulting from Reassessment of State Deferred Income Taxes(g)	(4)	—	—	—
Recovery of Costs Resulting From Distribution Rate Case Order(h)	—	—	(17)	(0.03)
Adjusted (non-GAAP) Operating Earnings	$ 522	$ 0.61	$ 697	$ 1.05

	Six Months Ended June 30,			
	2012		2011	
(All amounts after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income	$ 486	$ 0.62	$1,288	$ 1.94
Mark-to-Market Impact of Economic Hedging Activities(a)	(167)	(0.21)	164	0.25
Unrealized (Gains) Losses Related to NDT Fund Investments(b)	(17)	(0.02)	(30)	(0.04)
Plant Retirement and Divestitures(c)	7	0.01	27	0.04
Constellation Merger and Integration Costs(d)	180	0.23	15	0.02
Amortization of Acquired Contracts(e)	358	0.46	—	—
Amortization of the Fair Value of Certain Debt(f)	(3)	—	—	—
Reassessment of State Deferred Income Taxes(g)	(121)	(0.16)	—	—
Recovery of Costs Resulting From Distribution Rate Case Order(h)	—	—	(17)	(0.03)
Maryland Commitments(i)	227	0.29	—	—
FERC Settlement(j)	172	0.22	—	—
Other Acquisition Costs(k)	3	—	—	—
Non-Cash Charge Resulting from Illinois Tax Rate Change Legislation(l)	—	—	29	0.04
Adjusted (non-GAAP) Operating Earnings	$1,125	$ 1.44	$1,476	$ 2.22

(a) Reflects the impact of (gains) losses for the three and six months ended June 30, 2012 (net of taxes of $(81) million and $(109) million, respectively) and for the three and six months ended June 30, 2011 (net of taxes of $49 million and $108 million, respectively) on Generation's economic hedging activities, net of intercompany eliminations. See Note 8 of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(b) Reflects the impact of (gains) for the three and six months ended June 30, 2012 (net of taxes of $(37) million and $46 million, respectively) and for the three and six months ended June 30, 2011 (net of taxes of $19 million and $58 million, respectively) on Generation's NDT fund investments for Non-Regulatory Agreement Units. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Primarily reflects incremental accelerated depreciation associated with the retirement of four fossil generating units and compensation for the three and six months ended June 30, 2012 (net of taxes of $1 million and $3 million, respectively) and for the three and six months ended June 30, 2011 (net of taxes of $7 million and $17 million, respectively) for operating two of the units past their planned May 31, 2011 retirement date under a FERC-approved reliability-must-run rate schedule. For 2012, also reflects revenues and operating expenses for the three and six months ended June 30, 2012 (net of taxes of $(2) million and $0 million, respectively) related to three generation facilities to be required to be sold within 180 days of the merger. See Note 13 of the Combined Notes to Consolidated Financial Statements and "Results of Operations — Generation" for additional detail related to the generating unit retirements.

(d) Reflects certain costs incurred for the three and six months ended June 30, 2012 (net of taxes of $44 million and $76 million, respectively) and for the three months ended June 30, 2011 (net of taxes of $10 million) associated with the Constellation merger including employee-related expenses and integration initiatives. See Note 3 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, 2012 (net of taxes of $183 million and $234 million, respectively) of amortization of acquired energy contracts recorded at fair value at the merger date. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

(f) Represents the non-cash amortization of certain debt (net of taxes of $(2) million) recorded at fair value at the merger date expected to be retired in 2013. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

(g) Reflects a one-time, non-cash benefit related to a change in state deferred tax rates resulting from a reassessment of anticipated apportionment of Exelon's deferred taxes as a result of the merger. See Note 10 of the Combined Notes to Consolidated Financial Statements for additional detail related to the impact of the Illinois tax rate change legislation.

(h) Reflects a one-time benefit in the second quarter of 2011 to recover previously incurred costs as a result of the May 2011 ICC rate order (net of taxes of $5 million). See Note 4 of the Combined Notes to the Consolidated Financial Statements for additional information.

(i) 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 3 of the Combined Notes to Consolidated Financial Statements for additional information.

(j) 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 prior period hedging and risk management transactions. See Note 16 of the Combined Notes to Consolidated Financial Statements for additional information.

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

(l) Reflects a one-time, non-cash charge to remeasure deferred taxes at higher corporate tax rates pursuant to the Illinois tax rate change legislation. See Note 10 of the Combined Notes to the Consolidated Financial Statements for additional detail related to the impact of the Illinois tax rate change legislation.

Outlook for the Remainder of 2012 and Beyond.

Merger with Constellation

On March 12, 2012, the Exelon and Constellation merger was completed. On the merger date, Constellation's shareholders received 0.930 shares of Exelon common stock in exchange for each share of Constellation common stock. Based on Exelon's opening share price on March 12, 2012, Constellation shareholders and equity award holders received $7.4 billion in total equity value. The resulting company retained the Exelon name and is headquartered in Chicago.

Exelon has incurred and will continue to incur costs associated with evaluating, structuring and executing the merger transaction itself, 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.

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For the three and six months ended June 30, 2012, expense has been recognized for costs incurred to achieve the merger as follows:

Merger and Integration Costs:	Pre-tax Expense Three Months Ended June 30, 2012				
	Generation(a)	ComEd	PECO	BGE(a)	Exelon(a)
Transaction(b)	$ —	$ —	$ —	$ —	$ 2
Maryland Commitments	—	—	—	—	—
Employee-Related(c)	39	—	2	—	43
Other(d)	55	—	2	2	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(b)	$ —	$ —	$ —	$ —	$ 52
Maryland Commitments	35	—	—	139	328
Employee-Related(c)	86	—	7	—	101
Other(d)	83	2	4	3	103
Total	$ 204	$ 2	$ 11	$ 142	$ 584

(a) For Exelon, Generation and BGE, includes the operations of the acquired businesses from the date of the merger, March 12, 2012, through June 30, 2012.
(b) 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.
(c) Costs primarily for employee severance, pension and OPEB expense and retention. ComEd and BGE established a regulatory asset of $16 million and $18 million, respectively, for severance benefits costs which are expected to be recovered over a five-year period. These costs are not included in the table above.
(d) Costs to integrate Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements.

Exelon projects incurring total additional merger-related costs, primarily in 2012 and 2013, of approximately $550 million, of which approximately $450 million is expected to be recognized as expense, and approximately $100 million is expected to be capitalized in connection with the integration of systems.

In addition, pursuant to conditions set forth by the MDPSC in its approval of the merger transaction, Generation expects to incur capital expenditures of $95 million to $120 million for the requirement to cause construction of a headquarters building in Baltimore for its competitive energy businesses (expected to be completed in 2 to 3 years) and up to $625 million for development of 285-300 MW of new electric generation facilities in Maryland (expected to be completed over the next ten years). The accounting treatment for the construction costs of the headquarters building in Baltimore may vary depending on the structure of the transaction.

Exelon and Constellation have also agreed to enter into contracts to sell three Constellation generating stations located in PJM within 150 days (subsequently extended 30 days by DOJ) following the merger completion and will be required to complete the divestitures within 30 days after receipt of regulatory approvals. On August 8, 2012, a subsidiary of Generation reached an agreement to sell three Maryland generating stations and associated assets to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on the merger and sale.

Japan Earthquake and Tsunami and the Industry's Response

On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co.

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. The nuclear industry has already taken specific steps to respond. Generation has completed actions requested by the Institute of Nuclear Power Operations (INPO), which included tests that verified its emergency equipment is available and functional, walk-downs on its procedures related to critical safety equipment, confirmation of event response procedures and readiness to protect the spent fuel pool, and verification of 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 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 to commercial reactor licensees operating in the United States for compliance no later than December 31, 2016. In summary, the orders require licensees: (1) to provide sufficient onsite portable equipment and resources to maintain or restore cooling capabilities for the containment, core, and spent fuel pool until offsite equipment is available and have offsite equipment and resources available to sustain cooling functions indefinitely; (2) to improve the venting systems with boiling water reactor Mark I or Mark II containments (or for the Mark II plants, install new systems) that help prevent or mitigate core damage in the event of a serious accident by making the systems accessible and operable in the event of a prolonged station blackout and inadequate cooling; and (3) to install instrumentation to provide a reliable indication of water level in the spent fuel pool.

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 NRC staff has scheduled a number of meetings to obtain stakeholder input on implementation guidance for the orders and information requests. Generation is assessing the impacts of the 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 is not anticipated to be significant to Generation's financial position, results of operations, or cash flows over the next five years (required implementation deadline of December 31, 2016). However, until the specific requirements and guidance for each order, request for information, and recommendation are established after obtaining stakeholder input, Generation is unable to determine with specificity the impact the recommendations may have on its nuclear units. Additionally, Generation's current assessments are specific to the Tier 1 recommendations and information requests as the NRC has not taken 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 2011 Form 10-K for further discussion of the risk factors.

Generation's plan for increasing the output through uprates of its nuclear generating stations has not changed as a result of the situation in Japan. However, Generation will continue to monitor NRC directives and guidance that may impact the uprates and, as it has in the past, evaluate each project at the appropriate time and cancel or defer any uprate project that is not considered economical, whether due to energy prices, potential increased regulation, or other factors.

Economic and Market Conditions

Exelon has exposure to various market and financial risks, including the risk of price fluctuations in the wholesale and retail power markets. Wholesale 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 wholesale market prices that Generation's power plants can obtain for their output, (2) the rate of expansion of subsidized low carbon generation such as wind energy in the markets in which Generation's output is sold, (3) the impacts on energy demand of factors, such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) regulatory and legislative actions, such as the U.S. EPA's CSAPR and the MATS. See *Environmental Matters* section below for further detail on CSAPR and the MATS.

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.

The market price for electricity is also affected by changes in the demand for electricity. Poor economic conditions, milder than normal weather, unexpected or unusual weather patterns and the growth of energy efficiency and demand response programs can depress demand. The result is that higher-cost generating resources do not run as frequently, putting downward pressure on market prices for electricity and/or capacity. The continued sluggish economy in the United States has led to a decline in demand for electricity. ComEd and BGE are projecting load demand to remain essentially flat in 2012 compared to 2011, while PECO is projecting a decline of 2.0% in 2012 compared to 2011 as a result of the above drivers in addition to reduced oil refinery load in its service territory.

Since the third quarter of 2011, forward natural gas prices for 2013 and 2014 have declined significantly; reflecting an increase in supply due to strong natural gas production (due to shale gas development) and significantly warmer than normal weather, as well as generally lowered expectations for gas demand and economic growth rates. Wholesale power prices have likewise decreased in response in part to the lower gas prices, and to the late December 2011 judicial stay of the U.S. EPA's CSAPR and various other market factors.

Exelon also 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, 2012, approximately 40%, or $4.3 billion, of the Registrants' available credit facilities were with European banks. The credit facilities include $10.7 billion in aggregate total commitments of which $8.0 billion was available as of June 30, 2012. There were no borrowings under the Registrants' credit facilities as of June 30, 2012. See Note 9 of the Combined Notes to Consolidated Financial Statements for additional information on the credit facilities.

Exelon routinely reviews its hedging policy, operating and capital costs, capital spending plans, 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. Based on the results of these assessments, Exelon management believes it is able to respond to changing market conditions in a manner that ensures reliable and safe service for Exelon's customers and sufficient liquidity to operate Exelon's businesses.

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 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 2012 and 2013. 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, 2012, the percentage of expected generation hedged was 99%-102%, 79%-82% and 46%-49% for 2012, 2013 and 2014, 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, excluding owned generation to be retired or sold in 2012. Equivalent sales represent all hedging products, which include other derivatives and certain non-derivative contracts including sales to ComEd, PECO and BGE to serve their retail load. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures coal 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 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 56% of Generation's uranium concentrate requirements from 2011 through 2015 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. Generation uses long-term contracts and financial instruments such as over-the-counter and exchange-traded instruments to mitigate price risk associated with certain commodity price exposures. ComEd, PECO and BGE mitigate exposure as a result of the regulatory mechanisms that allow them to recover procurement costs from retail customers.

New Growth Opportunities

Nuclear Uprate Program. Generation has announced a series of planned power uprates across its nuclear fleet that would result in between 1,175 and 1,300 MWs at an overnight cost of approximately $3.5 billion in 2012 dollars, of which approximately $900 million has been spent through June 30, 2012. Overnight costs do not include financing costs or cost escalation. Using proven technologies, the projects take advantage of new production and measurement technologies, new materials and learning from a half-century of nuclear power operations. Uprate projects, representing approximately 75% of the planned uprate MWs, are underway at the Limerick, Three Mile Island (TMI) and Peach Bottom nuclear stations in Pennsylvania and the Byron, Braidwood, Dresden, LaSalle and Quad Cities plants in Illinois. The remaining uprate MWs will come from additional projects across Generation's nuclear fleet beginning in 2012 and ending in 2018. At 1,300 nuclear-generated MWs, the uprates would displace 6 million metric tons of carbon emissions annually that would otherwise come from burning fossil fuels. The uprates are being undertaken pursuant to an organized, strategically sequenced implementation plan. The implementation effort includes a periodic review and refinement of the project in light of changing market conditions. The amount of expenditures to implement the plan ultimately will depend on economic and policy developments and projected sources and uses of funds, and will be made on a project-by-project basis in accordance with Exelon's normal project evaluation standards. A review of the LaSalle Extended Power Uprate was performed in the second quarter and the completion of the project was deferred by two years, primarily as a result of market conditions. The ability to implement several projects requires the successful resolution of various technical issues. The resolution of these issues may affect the timing and amount of the power increases associated with the power uprate initiative. Through June 30, 2012, Generation has added 250 MWs of nuclear generation through its uprate program, with another 82 MWs scheduled to be added during the remainder of 2012.

Generation Renewable Development. Generation plans to construct multiple wind facilities in 2012, resulting in approximately 400 MWs of additional renewable generation. Total costs for the facilities are expected to be approximately $715 million. Total costs incurred through June 30, 2012 were approximately $400 million. Upon completion of these wind facilities, Generation will have approximately 1,300 MW of wind capacity within its portfolio of generating assets.

Generation is currently constructing a solar PV facility in Los Angeles County, California. The facility is expected to become operational during the first quarter of 2013. Upon completion, the facility will add 230 MWs to Generation's renewable generation fleet. Total costs for the facility are expected to be approximately $1.4 billion. Total costs incurred through June 30, 2012 were approximately $250 million. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Utility Infrastructure. During the fourth quarter of 2011, EIMA was enacted in Illinois, which provides for a cost recovery structure under which ComEd plans to invest an additional $2.6 billion over a ten-year period, beginning in 2012, to modernize Illinois' electric utility infrastructure and for greater certainty related to the recovery of costs by a utility through a pre-established distribution formula rate tariff.

In 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan, representing an investment of up to a total of $650 million, including its $200 million SGIG, on its smart grid and smart meter infrastructure.

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, including its $200 million SGIG for smart grid and other related initiatives.

See the Regulatory and Legislative Matters section below and Note 4 of the Combined Notes to Consolidated Financial Statements for additional information on the utility infrastructure projects.

Liquidity and Cost Management

Credit Facilities. Exelon, Generation, PECO and BGE have unsecured syndicated revolving and bilateral credit facilities with aggregate bank commitments of $2.9 billion, $5.6 billion, $0.6 billion and $0.6 billion, respectively. Their syndicated revolving credit facilities expire between October 2013 and March 2016. The bilateral facilities at Exelon and Generation have expirations that range from September 2013 through March 2016.

On March 28, 2012, ComEd replaced its unsecured revolving credit facility with a new unsecured facility with aggregate bank commitments of $1.0 billion. The new facility expires in March 2017, unless extended in accordance with the agreement.

On July 18, 2012, Exelon Corporate, Generation, PECO and BGE began the process of amending and 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 amended credit facilities will reflect current market pricing and, maturities of five years from the close of the transactions. The transactions are expected to close and become effective in August 2012. 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. The maturity of the $1.5 billion Constellation Credit Agreement will be amended to December 31, 2012. See Note 9 of the Combined Notes to Consolidated Financial Statements for further information regarding the credit facility terms.

Exelon expects lower liquidity requirements as a result of the merger due to the matching of load and generation.

Cost Management. Exelon is committed to operating its businesses responsibly and managing its operating and capital costs in a manner that serves its customers and produces value for its shareholders. Exelon is also committed to an ongoing strategy to become more effective, efficient and innovative. Exelon is committed to maintaining a cost control focus and continues to analyze cost trends to identify future cost savings opportunities and implement more planning and performance-measurement tools to allow it to better identify areas for sustainable productivity improvements and cost reductions across the Registrants.

Environmental Matters

Exelon 2020. In 2008, Exelon announced a comprehensive business and environmental strategic plan, which details an enterprise-wide strategy and a wide range of initiatives being pursued by Exelon to reduce, offset, or displace more than 15 million metric tons of GHG emissions per year by 2020 (from 2001 levels). Exelon has incorporated Exelon 2020 into its overall business plans, and as further legislation and regulation imposing requirements on emissions of air pollutants are promulgated, its emissions reduction efforts will position Exelon to benefit from the long-term positive impact of the requirements on capacity and energy prices while minimizing the impact of costs of compliance on Exelon’s operations, cash flows or financial position.

Environmental Legislative and Regulatory Developments

Exelon supports the promulgation of environmental regulation 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 Congress that would prohibit or impede the U.S. EPA’s rulemaking efforts. The timing of the consideration of such legislation is unknown.

Air. Beginning with the CSAPR, the air requirements are being implemented through a series of increasingly stringent regulations relating to conventional air pollutants (e.g., NO_x, SO_2 and particulate matter) as well as HAPs (e.g., acid gases, mercury and other heavy metals). It is expected that the U.S. EPA will complete a review of NAAQS in the 2012 — 2013 timeframe for particulate matter, nitrogen dioxide, sulfur dioxide and lead. This review will likely result in more stringent emissions limits on fossil-fuel fired electric generating stations. There is opposition among fossil fuel-fuel fired generation owners to the potential stringency and timing of these air regulations, and the House Commerce and Energy Committee and several of its subcommittees have held a number of hearings on these issues.

On July 7, 2011, the U.S. EPA published 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. On October 14, 2011 and February 7, 2012, the U.S. EPA proposed for public comment certain technical corrections to CSAPR, including correction of data errors in determining generation unit allowances and state allowance budgets. These corrections will increase the number of emission allowances available under the CSAPR. In addition, the proposal defers until 2014 penalties that will involve surrender of additional allowances should states not meet certain levels of emission reductions. This deferral is intended to increase the liquidity of allowances during the initial years of transition from CAIR to CSAPR. On June 12, 2012, the U.S. EPA issued its final technical corrections and associated updates to state emission budgets, and generating unit emission allowance allocations.

Several entities challenged the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit, and requested a stay of the rule pending the Court's consideration of the matter on the merits. Exelon received permission from the Court to intervene in support of CSAPR and in opposition to the stay. On December 30, 2011, the Court granted a stay and directed the U.S. EPA to continue the administration of CAIR in the interim. The Court ordered an expedited case management schedule that resulted in oral argument on April 13, 2012. It is unknown when the Court will issue its decision on the merits. Exelon believes that CSAPR is a valid exercise of the U.S. EPA's authority and discretion under the Clean Air Act. Upon preliminary review, it is expected that once implemented CSAPR will modestly increase power prices over the short term, which would result in a net benefit to Generation's and CENG's results of operations and cash flows.

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 new source performance standards 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 petitioned the Court to intervene in support of the rule.

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, Generation owns three base-load, coal-fired generation units in Maryland that were acquired in the merger with Constellation — Brandon Shores, H.A. Wagner and C.P. Crane. However, in connection with certain of the regulatory approvals required for the merger, Exelon agreed to divest these generating stations. It is anticipated that these plants are well positioned to comply with CSAPR and MATS, since Maryland has adopted SO_2, NO_x, and mercury emission limits under its Healthy Air Act and Clean Power Rule that are generally consistent with the requirements of CSAPR and MATS.

The cumulative impact of these 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.

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 PSD and Title V operating permit sections of the Clean Air Act for new and modified stationary sources that became effective on January 2, 2011. On April 13, 2012, the U.S. EPA published proposed regulations for new source performance standards (NSPS) for GHG emissions from new fossil-fueled power plants, greater than 25 MW, that would require the plants to limit CO_2 emissions. 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.

Exelon supports comprehensive climate change legislation by the U.S Congress, including a mandatory, economy-wide cap-and-trade program for GHG emissions that balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions. Several bills containing provisions for legislation of GHG emissions were introduced in Congress from January 2009 through January 2011, but none were passed by both houses of Congress.

Water. 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. Regulations adopted by the U.S. EPA in 2004 applicable to large electric generating stations were withdrawn in 2007 following a decision by the U.S. Second Circuit Court of Appeals that invalidated many of the rule's significant provisions and remanded the rule to the U.S. EPA for further consideration and revision. 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 July 27, 2012. 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. 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. On July 18, 2012, the U.S. EPA announced that it had agreed to extend the deadline to issue a final rule until June 27, 2013.

It is unknown at this time whether the final regulations or permit will require closed-cycle cooling at Salem. In addition, the economic viability of Generation's other power generation 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.

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. The Generation plants that would be affected by the proposed rules are Keystone and Conemaugh in Pennsylvania and Brandon Shores, H.A. Wagner, and C.P. Crane in Maryland. Keystone and Conemaugh each have on-site landfills that meet the requirements of Pennsylvania solid waste regulations for non-hazardous waste disposal. The Maryland facilities have exclusive use of a newly constructed landfill that meets the RCRA hazardous waste requirements. In connection with certain of the regulatory approvals required for the merger with Constellation, Exelon agreed to divest the Maryland generating stations and the landfill is included in the sale. As a result, only the adoption of the hazardous waste standards would have an impact on Exelon's Pennsylvania facilities, and the extent of that impact is unknown at this time. The U.S. EPA has not announced a target date for finalization of the CCR rules.

See Note 16 of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Regulatory and Legislative Matters

Energy Infrastructure Modernization Act (Exelon and ComEd).

Background

EIMA provides a structure for substantial capital investment over a ten-year period to modernize Illinois' electric utility infrastructure. EIMA allows the recovery of costs by a utility through a pre-established performance-based formula rate tariff, approved by the ICC; and will provide greater certainty as to the recovery of those costs. ComEd made an initial contribution of $15 million (recognized as expense in 2011) to a new Science and Technology Innovation Trust fund on July 31, 2012, and will make annual contributions of $4 million beginning in 2012, which will be used for customer education for as long as the AMI Deployment Plan remains in effect. In addition, ComEd will contribute $10 million per year for five years, as long as ComEd is subject to EIMA, to fund customer assistance programs for low-income customers, which amounts will not be recoverable through rates.

Capital Investment

On January 6, 2012, ComEd filed its Infrastructure Investment Plan with the ICC. Under that plan, ComEd will invest approximately $2.6 billion over ten years to modernize and storm-harden its distribution system and to implement smart grid technology. These investments will be incremental to ComEd's historical level of capital expenditures. The ICC filing specifically included ComEd's $233 million investment plan for 2012. On April 23, 2012, ComEd filed its initial AMI Deployment Plan with the ICC. On June 22, 2012, the ICC approved the AMI Deployment Plan with certain modifications. Implementation of the investment plan began in early 2012 while smart meter installation in homes and businesses is expected to begin later in 2012, but is subject to the rehearing described below.

Formula Rate Tariff

On November 8, 2011, ComEd filed its initial formula rate tariff and associated testimony based on 2010 costs and 2011 plant additions. The primary purpose of that proceeding was to establish the formula rate under which rates will be calculated going-forward, and the initial rates, which went into effect in late June. On May 30, 2012, the ICC issued its final Order (Order) in that proceeding. The Order reduced the annual revenue requirement by $168 million, or approximately $110 million more than proposed by ComEd. Of this incremental revenue requirement reduction, approximately $50 million reflected the ICC's determination that certain costs should be recovered through alternative rate recovery tariffs available to ComEd or will be reflected in the annual reconciliation, thereby primarily delaying the timing of cash flows. The incremental revenue reduction also reflected a $35 million reduction for the disallowance of return on ComEd's pension asset, a $10 million reduction for incentive compensation related adjustments, and $15 million of reductions for various adjustments for cash working capital, operating reserves, and other technical items. In the second quarter of 2012, ComEd recorded a reduction of revenue of approximately $100 million pre-tax to decrease the regulatory asset for the 2011 periods and for the first three months of 2012 consistent with the terms of the Order. On June 5, 2012, ComEd filed its application for rehearing with the ICC. On June 22, 2012, the ICC granted expedited rehearing on ComEd's pension asset recovery, the use of average or year-end rate base in determining ComEd's reconciliation revenue requirement and the interest rate charged on over/under recovered costs. The expected schedule for the rehearing allows for a decision by September 19, 2012. As a further result of the Order, on July 6, 2012, ComEd filed for rehearing of the AMI Deployment Plan to amend the timing and amount of the capital investment under that plan. On July 11, 2012, the ICC granted rehearing on ComEd's AMI Deployment Plan. A final order on rehearing is due by December 7, 2012.

Annual Reconciliation

ComEd will file an annual reconciliation of the revenue requirement in effect in a given year to reflect actual costs that the ICC determines are prudently and reasonably incurred for such year. ComEd made its initial 2011 reconciliation filing on April 30, 2012, which reconciled the 2011 revenue requirement in effect to ComEd's actual 2011 costs incurred (the rates will take effect in January 2013). ComEd updated its 2011 reconciliation filing on June 12, 2012 to reflect the impacts of the Order discussed above. A similar reconciliation with respect to 2012 will be filed in second quarter 2013 with any adjustments to rates taking effect in January 2014. As of June 30, 2012 and December 31, 2011, ComEd recorded an estimated net regulatory asset of $26 million and $84 million, respectively, which represents the ICC's approved distribution formula and associated rulings as of June 30, 2012 and ComEd's best estimate of the probable increase in distribution rates expected to be approved by the ICC to provide for recovery of prudent and reasonable costs incurred for the twelve months ended December 31, 2011 and for the six months ended June 30, 2012. The evidentiary hearing in ComEd's 2011 reconciliation rate case is expected to begin on September 25, 2012, with a final order due by December 26, 2012.

Appeal of 2007 Illinois Electric Distribution Rate Case (Exelon and ComEd). The ICC issued an order in ComEd's 2007 electric distribution rate case (2007 Rate Case) approving a $274 million increase in ComEd's annual delivery services revenue requirement, which became effective in September 2008. In the order, the ICC authorized a 10.3% rate of return on common equity. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). The Court issued a decision on September 30, 2010, ruling against ComEd on the treatment of post-test year accumulated depreciation and the recovery of system modernization costs via a rider (Rider SMP). The ICC subsequently initiated a proceeding on remand. On February 23, 2012, the ICC issued an order in the remand proceeding requiring ComEd to provide a refund of approximately $37 million to customers related to the treatment of post-test year accumulated depreciation issue. On March 26, 2012, ComEd filed a notice of appeal. ComEd has recognized for accounting purposes its best estimate of any refund obligation.

Advanced Metering Program Proceeding (Exelon and ComEd). In October 2009, the ICC approved a modified version of ComEd's system modernization rider proposed in the 2007 Rate Case, Rider AMP (Advanced Metering Program). ComEd collected approximately $24 million under Rider AMP through December 31, 2011. Several other parties, including the Illinois Attorney General, appealed the ICC's order on Rider AMP. In ComEd's 2010 electric distribution rate case, the ICC approved ComEd's transfer of other costs from recovery under Rider AMP to recovery through base electric distribution rates. On March 19, 2012, the Court reversed Rider AMP, concluding that the ICC's October 2009 approval of the rider constituted single-issue ratemaking. ComEd filed a Petition for Leave to Appeal to the Illinois Supreme Court on April 23, 2012. ComEd believes any refund obligation associated with Rider AMP should be prospective from no earlier than the date of the Court's order on March 19, 2012, which would have an immaterial impact at ComEd and Exelon.

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 derivatives, 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 is continuing to evaluate the rule, and it has not yet determined whether it will be required to register all or a part of Exelon's commercial business as a swap dealer or major swap participant. 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 the 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 the amount of exchange margin cash postings in lieu of letters of credit currently issued on over-the-counter contracts. Whether or not the new regulations apply directly to Generation, it estimates that it may be required to make up to $1 billion of additional collateral postings based upon market conditions as of June 30, 2012. The level of collateral required would depend on multiple factors, including but not limited to market conditions, derivative activity levels and Generation's credit ratings. Generation has adequate credit facilities and flexibility in its hedging program to accommodate these legislative or market changes. In addition, the final regulations may impose substantial new and ongoing compliance and infrastructure requirements on us, which may amount to several million dollars per year. Generation continues to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on its results of operations, cash flows or financial position.

New Electric Generation Legislation and Regulations. Various states have implemented or proposed policies to subsidize generation that would artificially depress 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 a 700 MW combined cycle gas turbine in Waldorf, Maryland, with a projected commercial operation date of June 1, 2015. The CfD provides the utilities would pay (or receive) the difference between CPV's contract price and the revenues it receives for capacity and energy from bidding the unit into the PJM markets. The utilities have filed written comments on the revised CfD that has been proposed by the MDPSC's consultant and have provided further comments at a hearing on July 31, 2012. 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, which were executed by the state's utilities under protest. Similarly, in Illinois, legislation passed in the Senate and currently being considered in the House 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. All of these state efforts, if successful, could artificially depress wholesale capacity and/or energy prices. Other states could seek to establish similar programs, which could substantially impair Exelon's market driven position and could have a material effect on Exelon's financial results of operations, financial position and cash flows.

Exelon has taken action against some of these anti-competitive policies through legal, legislative and regulatory challenges. Additionally, PJM's Minimum Offer Price Rule (MOPR) was modified to preclude certain generators from artificially affecting capacity prices. See Note 4 of the Combined Notes to Consolidated Financial Statements for further details related to PJM's MOPR.

Reliability and Quality of Service Standards (Exelon and BGE). During its 2011 legislative session, the Maryland General Assembly passed legislation:

- directing the MDPSC to enact service quality and reliability regulations by July 1, 2012 relating to the delivery of electricity to retail electric customers,
- increasing existing penalties for failure to meet these and other MDPSC regulations, and
- directing the MDPSC to undertake certain studies addressing utility liability for certain customer damages, electric utility service restoration plans, and modifications to existing revenue decoupling mechanisms for extended service interruptions.

In May 2011, the Governor of Maryland signed this legislation into law, and the new service quality and reliability regulations became effective on May 28, 2012. These regulations could have a material impact on BGE's financial results of operations, cash flows and financial position. BGE did seek recovery of these costs in the current base rate case filed on July 27, 2012.

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2012 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 27, 2012, BGE filed an application for increases of $151 million and $53 million to its electric and gas base rates, respectively with the MDPSC. The requested rate of return on equity in the application is 10.5%. The new electric and gas distribution base rates are expected to take effect in late February 2013. BGE cannot predict how much of the requested increases, if any, the MDPSC will approve.

RICE NESHAP. On June 7, 2012 the U.S. EPA issued a proposed rule under section 112 of the CAA to amend the NESHAP for stationary reciprocating internal combustion engines (RICE). The proposed RICE NESHAP resulted from the settlement of various legal challenges to 2010 RICE NESHAP. The proposed rule would allow stationary emergency diesel engines without emissions controls to operate for up to 100 hours per year for maintenance and emergency demand response programs, including a temporary allowance until April 17, 2017, of up to 50 hours per year for peak shaving and other nonemergency use. This represents a significant increase in the 15 hours of emergency demand response that is currently permitted under the 2010 RICE NESHAP. As a result of the proposed rule, additional megawatts of demand response may be bid into PJM, resulting in a negative impact on capacity prices. Exelon expects to file comments to the proposed rule that would support a more limited expansion of demand response hours and peak shaving and other nonemergency use, expiring in 2017.

FERC Ameren Order (Exelon and ComEd). In July 2012, FERC issued an order to Ameren Corporation indicating that Ameren had improperly included acquisition premiums/ goodwill in its transmission formula rate, particularly in its capital structure and in the application of AFUDC. FERC also directed Ameren to make refunds for the implied increase in rates in prior years. ComEd expects Ameren will seek rehearing and/or appeal 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.

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 and PECO's combined 2011 Form 10-K and Constellation's and BGE's combined 2011 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, 2012, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2011.

Results of Operations

Net Income (Loss) on Common Stock by Registrant

	Three Months Ended June 30,		Favorable (Unfavorable) Variance	Six Months Ended June 30,		Favorable (Unfavorable) Variance
	2012(a)	2011		2012(a)	2011	
Exelon	$ 286	$ 620	$ (334)	$ 486	$1,288	$ (802)
Generation	166	443	(277)	334	938	(604)
ComEd	42	114	(72)	129	183	(54)
PECO	79	82	(3)	175	208	(33)
BGE	13	13	—	(20)	91	(111)

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

Results of Operations — Generation

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	Favorable (Unfavorable) Variance
Operating revenues	$ 3,753	$ 2,455	$ 1,298	$6,492	$5,098	$ 1,394
Purchased power and fuel expense	1,852	841	(1,011)	2,896	1,724	(1,172)
Revenue net of purchased power and fuel(a)	1,901	1,614	287	3,596	3,374	222
Other operating expenses						
Operating and maintenance	1,166	763	(403)	2,340	1,517	(823)
Depreciation and amortization	204	138	(66)	357	277	(80)
Taxes other than income	90	66	(24)	164	132	(32)
Total other operating expenses	1,460	967	(493)	2,861	1,926	(935)
Equity in loss of unconsolidated affiliates	(57)	—	(57)	(79)	—	(79)
Operating income	384	647	(263)	656	1,448	(792)
Other income and (deductions)						
Interest expense	(85)	(45)	(40)	(138)	(91)	(47)
Equity in losses of investments	—	—	—	—	—	—
Other, net	(76)	76	(152)	103	152	(49)
Total other income and (deductions)	(161)	31	(192)	(35)	61	(96)
Income before income taxes	223	678	(455)	621	1,509	(888)
Income taxes	58	235	177	289	571	282
Net income	165	443	(278)	332	938	(606)
Net income (loss) attributable to noncontrolling interests	(1)	—	1	(2)	—	2
Net income on common stock	$ 166	$ 443	$ (277)	$ 334	$ 938	$ (604)

(a) 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, 2012 Compared to Three Months Ended June 30, 2011. Generation's net income decreased compared to the same period in 2011 due to higher operating expenses, unfavorable NDT fund performance and losses on Generation's interest in CENG; offset by higher revenues, net of purchased power and fuel expense. The increase in operating expenses and revenues, net of purchased power and fuel expense was primarily due to the addition of Constellation in 2012.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011. Generation's net income decreased compared to the same period in 2011 due to higher operating expenses and losses on Generation's interest in CENG; offset by higher revenues, net of purchased power and fuel expense. The increase in operating expenses was primarily due to the addition of Constellation's financial results in 2012, costs associated with a settlement with FERC in March 2012 and transaction costs and employee-related costs associated with the merger. The increase in revenues, net of purchased power and fuel expense was also primarily due to the addition of Constellation in 2012.

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 Independent System Operator (ISO) / Regional Transmission Operator (RTO) and/or North American Electric Reliability Corporation (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 Florida Reliability Coordinating Council (FRCC) and the remaining portions of the SERC Reliability Corporation (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 Southwest Power Pool (SPP), covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the Western Electric Coordinating Council (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 Alberta Electric Systems Operator (AESO), Ontario Independent Electricity System Operator (OIESO) and the Canadian portion of MISO.

Generation evaluates the operating performance of its power marketing activities using the measure of revenue net of purchased power and fuel expense. 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. The following business activities are not allocated to a region, and are reported under Other: retail and wholesale gas, natural gas exploration and production activities, proprietary trading, energy efficiency and demand response, the design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems. 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 clean-coal assets held for sale; Brandon Shores, Wagner, and C.P. Crane; 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.

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For the three and six months ended June 30, 2012 and 2011, Generation's revenue net of purchased power and fuel expense by region were as follows:

	Three Months Ended June 30,			
	2012(a)	2011	Variance	% Change
Mid-Atlantic(b)	$ 883	$ 819	$ 64	7.8%
Midwest(c)	764	887	(123)	(13.9%)
New England	60	2	58	n.m.
New York	39	—	39	n.m.
ERCOT	119	(14)	133	n.m.
Other Regions(d)	34	3	31	n.m.
Total electric revenue net of purchased power and fuel expense	$ 1,899	$ 1,697	$ 202	11.9%
Proprietary Trading	15	16	(1)	(6.3%)
Mark-to-market gains (losses)	200	(124)	324	n.m.
Other(e)	(213)	25	(238)	n.m.
Total revenue net of purchased power and fuel expense	$ 1,901	$ 1,614	$ 287	17.8%

	Six Months Ended June 30,			
	2012(a)	2011	Variance	% Change
Mid-Atlantic(b)	$ 1,653	$ 1,732	$ (79)	(4.6%)
Midwest(c)	1,581	1,851	(270)	(14.6%)
New England	99	5	94	n.m.
New York	47	—	47	n.m.
ERCOT	153	(9)	162	n.m.
Other Regions(d)	48	(5)	53	n.m.
Total electric revenue net of purchased power and fuel expense	$ 3,581	$ 3,574	$ 7	0.2%
Proprietary Trading	11	22	(11)	(50.0%)
Mark-to-market gains (losses)	260	(272)	532	(195.6%)
Other(e)	(256)	50	(306)	n.m.
Total revenue net of purchased power and fuel expense	$ 3,596	$ 3,374	$ 222	6.6%

(a) Includes results for Constellation business transferred to Generation 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.
(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 and includes retail and wholesale gas, upstream natural gas, demand response, energy efficiency, the design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities, home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems. In addition, includes generation under the reliability-must-run rate schedule and generation of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities planned for divestiture as a result of the Exelon and Constellation merger. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date.

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Generation's supply sources by region are summarized below:

Supply source (GWh)	Three Months Ended June 30, 2012(a)	2011	Variance	% Change
Nuclear generation(b)				
Mid-Atlantic	12,277	11,172	1,105	9.9%
Midwest	22,860	21,995	865	3.9%
Total Nuclear Generation	35,137	33,167	1,970	5.9%
Fossil and Renewables(b)				
Mid-Atlantic(b)(d)	2,316	2,052	264	12.9%
Midwest	228	163	65	39.9%
New England	2,755	2	2,753	n.m
New York	—	—	—	0%
ERCOT(e)	2,177	207	1,970	n.m
Other Regions(f)	1,923	431	1,492	n.m
Total Fossil and Renewables	9,399	2,855	6,544	229.2%
Purchased power				
Mid-Atlantic(c)	7,111	707	6,404	n.m
Midwest	1,558	1,659	(101)	(6.1%)
New England	3,905	—	3,905	n.m
New York(c)	2,818	—	2,818	n.m
ERCOT(e)	6,686	1,834	4,852	n.m
Other Regions(f)	6,012	577	5,435	n.m
Total Purchased Power	28,090	4,777	23,313	n.m.
Total supply/sales by region(g)				
Mid-Atlantic(h)	21,704	13,931	7,773	55.8%
Midwest(i)	24,646	23,817	829	3.5%
New England	6,660	2	6,658	n.m
New York	2,818	—	2,818	n.m
ERCOT	8,863	2,041	6,822	n.m
Other Regions(f)	7,935	1,008	6,927	n.m
Total supply/sales by region	72,626	40,799	31,827	78.0%

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Supply source (GWh)	Six Months Ended June 30, 2012(a)	2011	Variance	% Change
Nuclear generation(b)				
Mid-Atlantic	24,341	23,543	798	3.4%
Midwest	46,058	44,816	1,242	2.8%
Total Nuclear Generation	70,399	68,359	2,040	3.0%
Fossil and Renewables(b)				
Mid-Atlantic(b)(d)	4,107	4,214	(107)	(2.5%)
Midwest	500	320	180	56.3%
New England	3,644	6	3,638	n.m.
New York	—	—	—	0%
ERCOT(e)	3,017	358	2,659	n.m.
Other Regions(f)	2,742	789	1,953	n.m.
Total Fossil and Renewables	14,010	5,687	8,323	146.4%
Purchased power				
Mid-Atlantic(c)	9,688	1,457	8,231	n.m.
Midwest	4,110	3,071	1,039	33.8%
New England	5,005	—	5,005	0%
New York(c)	3,753	—	3,753	0%
ERCOT(e)	9,518	3,459	6,059	175.2%
Other Regions(f)	7,781	1,134	6,647	n.m.
Total Purchased Power	39,855	9,121	30,734	n.m.
Total supply/sales by region(g)				
Mid-Atlantic(h)	38,136	29,214	8,922	30.5%
Midwest(i)	50,668	48,207	2,461	5.1%
New England	8,649	6	8,643	n.m.
New York	3,753	—	3,753	0%
ERCOT	12,535	3,817	8,718	n.m.
Other Regions(f)	10,523	1,923	8,600	n.m.
Total supply/sales by region	124,264	83,167	41,097	49.4%

(a) Includes results for Constellation business transferred to Generation 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 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 for the three and six months ended June 30, 2012.

(d) Excludes generation under the reliability-must-run rate schedule and generation of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities planned for divestiture as a result of the Exelon and Constellation merger.

(e) Generation from Wolf Hollow is included in purchased power for the three and six months ending June 30, 2011 and included within Fossil and Renewables for the three and six months ending June 30, 2012, due to the acquisition of Wolf Hollow in August, 2011.

(f) Other Regions includes South, West and Canada, which are not considered individually significant.

(g) Excludes physical proprietary trading volumes of 4,248 GWh and 1,496 GWh for the three months ended June 30, 2012 and 2011, respectively, and 6,077 GWh and 2,829 GWh for the six months ended June 30, 2012 and 2011, respectively.

(h) Includes sales to PECO through the competitive procurement process of 1,859 GWh and 1,636 GWh for the three months ended June 30, 2012 and 2011, respectively, and 3,488 GWh and 3,669 GWh for the six months ended June 30, 2012 and 2011, respectively. Sales to BGE of 1,076 GWh and 1,335 GWh were included for the three and six months ended June 30, 2012.

(i) Includes sales to ComEd under the RFP procurement of 865 GWh and 545 GWh for the three months ended June 30, 2012 and 2011, respectively, and 3,075 GWh and 1,796 GWh for the six months ended June 30, 2012 and 2011, respectively.

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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, 2012 as compared to the three and six months ended June 30, 2011.

$/MWh	Three Months Ended June 30, 2012(a)	Three Months Ended June 30, 2011	% Change
Mid-Atlantic(b)	$ 40.68	$ 58.79	(30.8%)
Midwest(c)	31.00	37.28	(16.8%)
New England	9.01	n.m.	n.m.
New York	13.84	n.m.	n.m.
ERCOT	13.43	(6.52)	n.m.
Other Regions(d)	4.28	3.08	39.0%
Electric revenue net of purchased power and fuel expense per MWh(e)(f)	26.15	41.59	(37.1%)

$/MWh(a)	Six Months Ended June 30, 2012(a)	Six Months Ended June 30, 2011	% Change
Mid-Atlantic(b)	$ 43.35	$59.29	(26.9%)
Midwest(c)	31.20	38.40	(18.8%)
New England	11.45	n.m.	n.m.
New York	12.52	n.m.	n.m.
ERCOT	12.21	(2.10)	n.m.
Other Regions(d)	4.56	(2.60)	n.m.
Electric revenue net of purchased power and fuel expense per MWh(e)(f)	28.82	42.97	(32.9%)

(a) Includes financial results for Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.
(b) Includes sales to PECO of $125 million (1,859 GWh) and $116 million (1,636 GWh) for the three months ended June 30, 2012 and 2011 respectively. Includes sales to PECO of $236 million (3,488 GWh) and $259 million (3,669 GWh) for the six months ended June 30, 2012 and 2011 respectively. Sales to BGE of $84 million (1,076 GWh) and $102 million (1,335 GWh) were included for the three and six months ended June 30, 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 planned for divestiture as a result of the merger.
(c) Includes sales to ComEd of $32 million (865 GWh) and $19 million (545 GWh) and settlements of the ComEd swap of $171 million and $109 million for the three months ended June 30, 2012 and 2011, respectively. Includes sales to ComEd of $115 million (3,075 GWh) and $70 million (1,796 GWh) and settlements of the ComEd swap of $336 million and $221 million for the six months ended June 30, 2012 and 2011, 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, 2012 and 2011 and excludes the mark-to-market impact of Generation’s economic hedging activities.
(f) Excludes retail gas activity, proprietary trading portfolio activity, compensation under the reliability-must-run rate schedule and fuel sales. Also excludes results from energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities. In addition, excludes the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities planned for divestiture as a result of the Exelon and Constellation merger. Also excludes amortization of intangible assets relating to commodity contracts recorded at fair value at the merger date.

Mid-Atlantic

Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011. The increase in revenue net of purchased power and fuel expense in the Mid-Atlantic of $64 million was primarily due to the addition of Constellation in 2012, partially offset by lower realized power prices, lower capacity revenues and increased nuclear fuel costs.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011. The decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic of $79 million was primarily due to lower realized power prices, lower capacity revenues and increased nuclear fuel costs, partially offset by the addition of Constellation in 2012.

Midwest

Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011. The decrease in revenue net of purchased power and fuel expense in the Midwest of $123 million was primarily due to lower capacity revenues, lower realized power prices and increased nuclear fuel costs. These decreases were partially offset by decreased congestion costs and favorable settlements on the ComEd swap.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011. The decrease in revenue net of purchased power and fuel expense in the Midwest of $270 million was primarily due to lower capacity revenues, lower realized power prices and increased nuclear fuel costs. These decreases were partially offset by decreased congestion costs and favorable settlements on the ComEd swap.

New England.

Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011. The $58 million increase in revenue net of purchased power and fuel expense in New England was as a result of the Constellation merger. Prior to the merger, New England was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011. The $94 million increase in revenue net of purchased power and fuel expense in New England was as a result of the Constellation merger. 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, 2012 Compared to Three Months Ended June 30, 2011. The $39 million increase in revenue net of purchased power and fuel expense in New York was as a result of the Constellation merger. Prior to the merger, New York was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011. The $47 million increase in revenue net of purchased power and fuel expense in New York was as a result of the Constellation merger. 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, 2012 Compared to Three Months Ended June 30, 2011. The $133 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily as a result of the Constellation merger. The legacy Generation ERCOT portfolio was relatively flat period over period.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011. The $162 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily as a result of the Constellation merger. The legacy Generation ERCOT portfolio was relatively flat period over period.

Other Regions.

Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011. The $31 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of the Constellation merger.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011. The $53 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of the Constellation merger.

Mark-to-market

Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011. 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 $200 million for the three months ended June 30, 2012 compared to losses of $124 million for the three months ended June 30, 2011. See Notes 7 and 8 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, 2012 Compared to Six Months Ended June 30, 2011. 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 $260 million for the six months ended June 30, 2012 compared to losses of $272 million for the six months ended June 30, 2011. See Notes 7 and 8 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, 2012 Compared to Three Months Ended June 30, 2011. The $238 million decrease in other revenue net of purchased power and fuel was primarily due to the amortization of the acquired energy contracts recorded at fair value at the merger date. This decrease was partially offset by results from retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities. In addition, other revenue net of purchased power and fuel includes the results of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities planned for divestiture as a result of the Exelon and Constellation merger. See Note 3 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, 2012 Compared to Six Months Ended June 30, 2011. The $306 million decrease in other revenue net of purchased power and fuel was primarily due to the amortization of the acquired energy contracts recorded at fair value at the merger date. This decrease was partially offset by compensation under the reliability-must-run rate schedule, results from retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities. In addition, other revenue net of purchased power and fuel includes the results of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities planned for divestiture as a result of the Exelon and Constellation merger. See Note 3 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, 2012 as compared to the same periods in June 30, 2011, 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 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,	
	2012	2011	2012	2011
Nuclear fleet capacity factor(a)	93.4%	89.6%	93.5%	92.2%
Nuclear fleet production cost per MWh(a)	$18.48	$19.41	$19.27	$19.06

(a) 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, 2012 Compared to Three Months Ended June 30, 2011. The nuclear fleet capacity factor increased primarily due to fewer refueling outage days, excluding Salem outages, during the three months ended June 30, 2012 compared to the same period in 2011. For the three months ended June 30, 2012 and 2011, refueling outage days totaled 51 and 103, respectively. The decrease in refueling outage days was primarily due to the timing of refueling outage activities performed in 2012 compared to 2011. Higher number of net MWhs generated, partially offset by higher nuclear fuel costs, higher plant operating and maintenance expense resulted in a lower production cost per MWh for the three months ended June 30, 2012 as compared to the same period in 2011.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011. The nuclear fleet capacity factor increased primarily due to fewer refueling outage days, excluding Salem outages, during the six months ended June 30, 2012 compared to the same period in 2011. For the six months ended June 30, 2012 and 2011, refueling outage days totaled 118 and 147, respectively. The decrease in refueling outage days was primarily due to the timing of refueling outage activities performed in 2012 compared to 2011. Higher nuclear fuel costs, higher plant operating and maintenance expense, partially offset by a higher number of net MWhs generated resulted in higher production cost per MWh for the six months ended June 30, 2012 as compared to the same period in 2011.

Operating and Maintenance Expense

The changes in operating and maintenance expense for the three and six months ended June 30, 2012 compared to the same period in 2011, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Labor, other benefits, contracting and materials	$ 242	$ 294
FERC settlement(a)	—	195
Constellation merger and integration costs	40	112
Corporate allocations(b)	79	102
Pension and non-pension postretirement benefits expense	39	54
Maryland commitments(c)	—	35
Bodily injury costs(d)	19	19
Nuclear refueling outage costs, including the co-owned Salem plant(e)	(65)	(51)
Other	49	63
Increase in operating and maintenance expense	$ 403	$ 823

(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) Reflects the impact of an increased share of corporate allocated costs due to the merger.
(c) Reflects costs incurred as part of the Maryland order approving the merger transaction.
(d) Reflects increase in asbestos-related bodily injury reserve recorded in the second quarter of 2012. See Note — 16 of the Combined Notes to Consolidated Financial Statements for additional information.
(e) Reflects the impact of decreased planned refueling outage days in 2012.

Depreciation and Amortization

The increase in depreciation and amortization for the three and six months ended June 30, 2012 as compared to the three and six months ended June 30, 2011 was primarily due to higher plant balances resulting from the addition of Constellation's plant balances. The increase in depreciation and amortization expense was also due capital additions and upgrades to legacy facilities.

Taxes Other Than Income

The increase in taxes other than income for the three and six months ended June 30, 2012 as compared to the three and six months ended June 30, 2011 was primarily due to the addition of Constellation's financial results in 2012.

Equity in Losses of Unconsolidated Affiliates

Equity in losses of unconsolidated affiliates for the three and six months ended June 30, 2012 primarily reflected the addition of the amortization of acquired energy contracts with CENG recorded at fair value at the merger date and the amortization of the basis difference of Generation's ownership interest in CENG in connection with the Merger.

Interest Expense

The increase in interest expense for the three and six months ended June 30, 2012 as compared to the three and six months ended June 30, 2011 was primarily due to the increase in long-term debt as a result of the merger.

Other, Net

Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011. 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 $12 million of expense in 2012 compared to $19 million of income in 2011 related to the contractual elimination of income tax benefit in 2012 and income tax expense in 2011 associated with the NDT funds of the Regulatory Agreement Units, $42 million of credit facility termination fees recorded in 2012 and the impact of $32 million one-time interest income from the NDT fund special transfer tax deduction recognized in 2011.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011. 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 $52 million and $46 million of income in 2012 and 2011, respectively, related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units, $42 million of credit facility termination fees recorded in 2012 and the impact of $32 million one-time interest income from the NDT fund special transfer tax deduction recognized in the second quarter of 2011.

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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, 2012 and 2011:

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Net unrealized gains (losses) on decommissioning trust funds	$ (35)	$ 11	$ 30	$ 54
Net realized gains (losses) on sale of decommissioning trust funds	$ 3	$ —	$ 40	$ (2)

Effective Income Tax Rate

The effective income tax rate was 26.0% and 46.5% for the three and six months ended June 30, 2012, respectively, compared to 34.7% and 37.8% for the same periods during 2011. See Note 10 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, 2012	Three Months Ended June 30, 2011	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	Favorable (Unfavorable) Variance
Operating revenues	$1,281	$1,444	$ (163)	$2,670	$2,910	$ (240)
Purchased power expense	587	716	129	1,208	1,505	297
Revenue net of purchased power expense(a)	694	728	(34)	1,462	1,405	57
Other operating expenses						
Operating and maintenance	331	268	(63)	650	534	(116)
Depreciation and amortization	152	136	(16)	300	270	(30)
Taxes other than income	69	70	1	144	147	3
Total other operating expenses	552	474	(78)	1,094	951	(143)
Operating income	142	254	(112)	368	454	(86)
Other income and (deductions)						
Interest expense, net	(74)	(86)	12	(156)	(172)	16
Other, net	3	4	(1)	7	8	(1)
Total other income and (deductions)	(71)	(82)	11	(149)	(164)	15
Income before income taxes	71	172	(101)	219	290	(71)
Income taxes	29	58	29	90	107	17
Net income	$ 42	$ 114	$ (72)	$ 129	$ 183	$ (54)

(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, 2012 Compared to Three Months Ended June 30, 2011. ComEd's net income for the three months ended June 30, 2012 was lower than the same period in 2011 primarily due to a reduction in revenue recorded as a result of the May 30, 2012 final Order issued by the ICC in ComEd's 2011 formula rate proceeding under EIMA. Contributing to the decrease in net income were one-time net benefits recognized pursuant to the May 2011 ICC Order in ComEd's 2010 Rate Case and higher operating and maintenance expenses in 2012. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011. ComEd's net income for the six months ended June 30, 2012 was lower than the same period in 2011 primarily due to higher operating and maintenance costs consisting of higher contracting costs and the impact of the one-time net benefits recognized pursuant to the May 2011 ICC Order in ComEd's 2010 Rate Case. Also contributing to the decrease in net income were higher depreciation and amortization expenses resulting from an increase in capital additions.

Operating Revenues and Purchased Power Expense

There are certain drivers to 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 its electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on electric revenue net of purchased power expense. See Note 4 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 electric generation suppliers. All ComEd customers have the ability to purchase electricity from an alternative electric generation supplier. The customer choice of electric generation supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and generation services. The number of retail customers purchasing electricity from competitive electric generation suppliers was 668,209 and 133,464 at June 30, 2012 and 2011, respectively, representing 17% and 3% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 62% and 61% of ComEd's retail kWh sales for the three and six months ended June 30, 2012, respectively, as compared to 56% and 55% for the three and six months ended June 30, 2011, respectively. On March 20, 2012, 169 Illinois municipalities approved referendums regarding electric supply aggregation. This approval will allow municipal officials to begin the process to identify alternative electric generation suppliers. As contracts with new generation suppliers take effect, ComEd expects the percentage of retail deliveries purchased from competitive electric generation suppliers to increase.

The changes in ComEd's electric revenue net of purchased power expense for the three and six months ended June 30, 2012 compared to the same periods in 2011 consisted of the following:

	Three Months Ended June 30, 2012 Increase (Decrease)	Six Months Ended June 30, 2012 Increase (Decrease)
Regulatory required programs	$ 23	$ 41
Weather — delivery	18	1
Pricing (rate cases)	15	47
Revenues subject to refund, net	14	39
Transmission	7	16
Volume — delivery	(7)	(6)
Uncollectible accounts recovery, net	(11)	(10)
Reversal of revenue subject to refund	(17)	(17)
Discrete impacts of the 2012 Distribution Rate Case Order	(100)	(88)
Other	24	34
Total increase (decrease)	$ (34)	$ 57

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 uncollectible accounts tariff, 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.

Weather — delivery

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 and delivery of electricity. Conversely, mild weather reduces demand. In addition to experiencing higher than normal temperatures in June 2012, Illinois experienced the warmest January through May period on record in 2012. The favorable weather conditions in the second quarter resulted in an increase in revenues net of purchased power expense for the three months ended June 30, 2012. For the six months ended June 30, 2012, the increase in revenues net of purchased power expense for the second quarter of 2012 was offset by unfavorable weather conditions as a result of the warm weather in the first quarter of 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 and six months ended June 30, 2012 and 2011, consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2012**	**2011**	**Normal**	**From 2011**	**From Normal**
Three Months Ended June 30,					
Heating Degree-Days	544	823	765	(33.9)%	(28.9)%
Cooling Degree-Days	423	237	218	78.5%	94.0%
Six Months Ended June 30,					
Heating Degree-Days	2,928	4,155	3,929	(29.5)%	(25.5)%
Cooling Degree-Days	462	237	218	94.9%	111.9%

Pricing (rate cases)

The ICC issued an Order (Order) in the 2010 Rate Case approving an increase in ComEd's annual revenue requirement. The order became effective June 1, 2011 resulting in higher revenues for the three and six months ended June 30, 2012 compared to the same periods in 2011. The increase due to the 2010 Rate Case was partially offset by lower rates effective June 20, 2012 resulting from the final Order issued in ComEd's 2011 formula rate proceeding under EIMA. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

Revenues subject to refund, net

ComEd records revenues subject to refund based upon its best estimate of customer collections that may be required to be refunded. As a result of the September 30, 2010 Illinois Appellate Court (Court) decision in the 2007 Rate Case that ruled against ComEd on the treatment of post-test year accumulated depreciation and the recovery of system modernization costs via Rider SMP, ComEd began recording revenue subject to refund prospectively through June 1, 2011, when the rates in the 2010 Rate Case became effective. During the three and six months ended June 30, 2012, ComEd did not record revenues subject to refund associated with any matters.

Transmission

ComEd's transmission rates are established based on a FERC-approved formula. ComEd's most recent annual formula rate update, filed in May 2012, reflects actual 2011 expenses and investments plus forecasted 2012 capital additions. Transmission revenues 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. ComEd set a record for the highest daily peak load of 23,753 MWs on July 20, 2011 which was reflected in the determination of transmission revenues billed beginning January 1, 2012 and transmission rates that went into effect on June 1, 2012. See Note 4 of the Combined Notes to Consolidated Financial Statements.

Volume — delivery

Revenues net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, reflecting decreased average usage per residential customer for the three and six months ended June 30, 2012 compared to the same periods in 2011.

Uncollectible accounts recovery

Represents recoveries under ComEd's uncollectible accounts tariff.

Reversal of revenue subject to refund

Revenues net of purchased power decreased as a result of the benefit recognized during the second quarter of 2011 for reversing a reserve for revenues subject to refund. Subsequent to ICC approval, ComEd began billing customers for Cash Working Capital (CWC) through its energy procurement rider on June 1, 2010 reflecting the costs included in ComEd's original request to amend the tariff. Because of the uncertainty regarding the methodology for determining CWC recovery, ComEd had been recording a reserve against a portion of these billings. The ICC order in the 2010 Rate Case clarifies the method for determining CWC, and as a result, ComEd reversed a $17 million reserve during the second quarter of 2011.

Discrete impacts of the 2012 Distribution Rate Case Order

EIMA provides a structure for establishing a performance-based formula rate tariff. EIMA provides for an annual reconciliation of the revenue requirement in effect under the formula rate to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. ComEd made its initial reconciliation filing on April 30, 2012 with respect to calendar year 2011 and the adjusted rates will take effect in January 2013 after ICC review. On May 30, 2012, the ICC issued its final Order (Order) in the proceeding to establish ComEd's formula rate under EIMA. The Order reduces the annual revenue requirement by $168 million by modifying or eliminating some of the elements of the formula. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

Other

Other revenues were higher during the three and six months ended June 30, 2012 compared to the same periods in 2011. 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 remediation costs associated with MGP sites.

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Operating and Maintenance Expense

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Increase (Decrease)	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	Increase (Decrease)
Operating and maintenance expense — baseline	$ 276	$ 236	$ 40	$ 537	$ 462	$ 75
Operating and maintenance expense — regulatory required programs(a)	55	32	23	113	72	41
Total operating and maintenance expense	$ 331	$ 268	$ 63	$ 650	$ 534	$ 116

(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, 2012 compared to the same periods in 2011, consisted of the following:

	Three Months Ended June 30 Increase (Decrease)	Six Months Ended June 30 Increase (Decrease)
Baseline		
Discrete impacts from 2010 Rate Case order(a)	$ 32	$ 32
Labor, other benefits, contracting and materials(b)	18	46
Pension and non-pension postretirement benefits expense	9	17
Incremental Storm Costs	(19)	(21)
Other	—	1
	40	75
Regulatory required programs		
Energy efficiency and demand response programs	31	48
Purchased power administrative costs	3	3
Uncollectible accounts expense — provision	(1)	3
Uncollectible accounts expense — recovery, net(c)	(10)	(13)
	23	41
Increase in operating and maintenance expense	$ 63	$ 116

(a) In May 2011, as a result of the 2010 Rate Case order, ComEd recorded one-time net benefits to reestablish previously expensed plant balances and to recover previously incurred costs related to Exelon's 2009 restructuring plan.
(b) The increase includes contracting costs resulting from new projects associated with EIMA. See Note 4 of the Combined Notes to the Financial Statements for additional information.
(c) On February 2, 2010, the ICC issued an order adopting ComEd's proposed tariffs filed in accordance with Illinois legislation providing public utilities the ability 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 starting with 2008 and prospectively.

Depreciation and Amortization Expense

Depreciation and amortization expense increased during the three and six months ended June 30, 2012 compared to the same periods in 2011 primarily due to higher plant balances and amortization of the regulatory assets recorded in December 2011 to defer significant storm costs pursuant to EIMA.

Taxes Other Than Income

Taxes other than income taxes decreased during the three and six months ended June 30, 2012 compared to the same period in 2011 primarily due to decreased 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

Interest expense decreased during the three and six months ended June 30, 2012 compared to the same period in 2011 due to favorable interest rates on outstanding long-term debt balances.

Effective Income Tax Rate

The effective income tax rate was 40.8% for the three months ended June 30, 2012 compared to 33.7% for the same period during 2011. The effective income tax rate was 41.1% for the six months ended June 30, 2012 compared to 36.9% for the same period during 2011. See Note 10 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, 2012	Three Months Ended June 30, 2011	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)				
Residential	6,674	6,277	6.3%	(2.7)%
Small commercial & industrial	7,888	7,763	1.6%	(1.8)%
Large commercial & industrial	6,839	6,698	2.1%	0.4%
Public authorities & electric railroads	293	286	2.4%	2.4%
Total Retail	21,694	21,024	3.2%	(1.3)%

Retail Deliveries to customers (in GWhs)	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)				
Residential	13,080	13,231	(1.1)%	(1.6)%
Small commercial & industrial	15,804	15,837	(0.2)%	(0.3)%
Large commercial & industrial	13,542	13,517	0.2%	0.6%
Public authorities & electric railroads	617	616	0.2%	3.3%
Total Retail	43,043	43,201	(0.4)%	(0.4)%

Number of Electric Customers	As of June 30, 2012	As of June 30, 2011
Residential	3,456,312	3,447,194
Small commercial & industrial	365,474	364,902
Large commercial & industrial	1,990	2,007
Public authorities & electric railroads	4,793	4,914
Total	3,828,569	3,819,017

Electric Revenue	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	% Change	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	% Change
Retail Delivery and Sales(a)						
Residential	$ 720	$ 800	(10.0)%	$1,496	$1,634	(8.4)%
Small commercial & industrial	306	386	(20.7)%	654	767	(14.7)%
Large commercial & industrial	94	95	(1.1)%	194	186	4.3%
Public authorities & electric railroads	9	12	(25.0)%	21	26	(19.2)%
Total Retail	1,129	1,293	(12.7)%	2,365	2,613	(9.5)%
Other Revenue(b)	152	151	0.7%	305	297	2.7%
Total Electric Revenues	$1,281	$ 1,444	(11.3)%	$2,670	$2,910	(8.2)%

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

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

Results of Operations — PECO

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	Favorable (Unfavorable) Variance
Operating revenues	$715	$842	$ (127)	$1,590	$1,996	$ (406)
Purchased power and fuel	296	408	112	707	1,042	335
Revenue net of purchased power and fuel(a)	419	434	(15)	883	954	(71)
Other operating expenses						
Operating and maintenance	172	172	—	375	378	3
Depreciation and amortization	54	50	(4)	107	98	(9)
Taxes other than income	42	51	9	74	106	32
Total other operating expenses	268	273	5	556	582	26
Operating income	151	161	(10)	327	372	(45)
Other income and (deductions)						
Interest expense, net	(31)	(34)	3	(62)	(68)	6
Other, net	2	3	(1)	5	8	(3)
Total other income and (deductions)	(29)	(31)	2	(57)	(60)	3
Income before income taxes	122	130	(8)	270	312	(42)
Income taxes	42	47	5	93	102	9
Net income	80	83	(3)	177	210	(33)
Preferred security dividends	1	1	—	2	2	—
Net income on common stock	$ 79	$ 82	$ (3)	$ 175	$ 208	$ (33)

(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

Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011. The decrease in net income was primarily due to unfavorable weather and a decline in load. The decrease in net income was partially offset by a decrease in labor, contracting and materials expense.

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011. The decrease in net income was primarily due to unfavorable weather and a decline in load. The decrease in net income was partially offset by lower operating and maintenance, taxes other than income and interest expenses. The decrease in operating and maintenance expense was primarily due to decreased labor, other benefits, contracting, materials and storm expenses.

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 441,000 and 306,900 at June 30, 2012 and 2011, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 67% and 65% of PECO's retail kWh sales for the three and six months ended June 30, 2012, respectively, compared to 58% and 51% for the three and six months ended June 30, 2011. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 42,100 and 14,000 at June 30, 2012 and 2011, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 58% and 42% of PECO's retail mmcf sales for the three and six months ended June 30, 2012, respectively, compared to 56% and 37% for the three and six months ended June 30, 2011.

The changes in PECO's operating revenues net of purchased power and fuel expense for the three months ended June 30, 2012 compared to the same period in 2011 consisted of the following:

	Increase (Decrease)		
	Electric	**Gas**	**Total**
Weather	$ (11)	$ (1)	$ (12)
Volume	(4)	—	(4)
Pricing	2	1	3
Regulatory required programs	5	—	5
Other	(7)	—	(7)
Total decrease	$ (15)	$—	$ (15)

The changes in PECO's operating revenues net of purchased power and fuel expense for the six months ended June 30, 2012 compared to the same period in 2011 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ (31)	$(25)	$(56)
Volume	(13)	1	(12)
Pricing	7	3	10
Regulatory required programs	3	—	3
Other	(15)	(1)	(16)
Total decrease	$ (49)	$(22)	$(71)

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 and six months ended June 30, 2012 compared to the same periods in 2011, operating revenues net of purchased power and fuel expense were lower due to the impact of unfavorable 2012 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, 2012 compared to the same periods in 2011 and normal weather consisted of the following:

				% Change	
Heating and Cooling Degree-Days	2012	2011	Normal	From 2011	From Normal
Three Months Ended June 30,					
Heating Degree-Days	337	331	463	1.8%	(27.2)%
Cooling Degree-Days	430	494	348	(13.0)%	23.6%
Six Months Ended June 30,					
Heating Degree-Days	2,251	2,837	2,939	(20.7)%	(23.4)%
Cooling Degree-Days	434	494	348	(12.1)%	24.7%

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, 2012 compared to the same periods in 2011 reflected the reduced oil refinery load in PECO's service territory and the impact of energy efficiency initiatives and weak economic conditions on customer usage. The decrease for the six months ended June 30, 2012 was partially offset by additional volumes due to the extra day from the leap year.

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, 2012 compared to the same periods in 2011 reflected higher overall effective rates due to decreased usage per customer across all customer classes. This was primarily offset by the refund of the tax cash benefit resulting from the adoption of the safe harbor method of tax accounting for electric distribution property in 2011. The refund was reflected on customer bills as a credit beginning January 1, 2012. 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 the smart meter and energy efficiency programs as well as the administrative costs for the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Other

The decrease in other electric revenues net of purchased power expense for the three and six months ended June 30, 2012 compared to the same periods in 2011 reflected a decrease in GRT revenue as a result of lower supplied energy service and a reduction in the GRT rate. 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	Six Months Ended June 30,		Increase
	2012	2011	(Decrease)	2012	2011	(Decrease)
Operating and Maintenance Expense — Baseline	$ 151	$ 154	$ (3)	$ 335	$ 340	$ (5)
Operating and Maintenance Expense — Regulatory Required Programs(a)	21	18	3	40	38	2
Total Operating and Maintenance Expense	172	172	—	375	378	(3)

(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, 2012 compared to the same periods in 2011, 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	$ (14)	$ (16)
Storm-related costs	1	(8)
Pension Benefits	3	6
Constellation merger and integration costs	4	11
Other	3	2
	(3)	(5)
Regulatory Required Programs		
Smart Meter	2	6
Energy Efficiency	1	(2)
GSA	—	(2)
	3	2
Decrease in operating and maintenance expense	$ —	$ (3)

Depreciation and Amortization Expense

The increase in depreciation and amortization expense for the three and six months ended June 30, 2012 compared to the same periods in 2011 was primarily due to ongoing capital expenditures.

Taxes Other Than Income

The decrease in taxes other than income for the three and six months ended June 30, 2012 compared to the same periods in 2011 was primarily due to decreased GRT collections as a result of lower revenues and a reduction in the GRT rate. An equal and offsetting decrease in GRT has been reflected in operating revenues during the current periods. The decrease in taxes other than income for the six months ended June 30, 2012 also reflects a sales and use tax reserve adjustment in the first quarter of 2012 resulting from the completion of the audit of tax years 2005 through 2010.

Interest Expense, Net

The decrease in interest expense, net for the three and six months ended June 30, 2012 compared to the same periods in 2011 was primarily due to lower interest expense as a result of the debt retirement in November 2011.

Other, Net

The decrease in Other, net for the six months ended June 30, 2012 compared to the same period in 2011 was due to decreased AFUDC-Equity. See Note 17 of the Combined Notes to the Consolidated Financial Statements for further details of the components of Other, net.

Effective Income Tax Rate

PECO's effective income tax rate was 34.4% and 36.2% for the three months ended June 30, 2012 and 2011, respectively, and 34.4% and 32.7% for the six months ended June 30, 2012 and 2011, respectively. See Note 10 of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in effective income tax rate.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	% Change	Weather-Normal % Change	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)								
Residential	2,929	3,075	(4.7)%	(0.7)%	6,095	6,665	(8.6)%	(1.7)%
Small commercial & industrial	1,959	2,026	(3.3)%	(1.9)%	3,910	4,165	(6.1)%	(3.5)%
Large commercial & industrial	3,743	3,954	(5.3)%	(4.9)%	7,380	7,642	(3.4)%	(3.4)%
Public authorities & electric railroads	237	229	3.5%	3.5%	474	471	0.6%	0.6%
Total Electric Retail	8,868	9,284	(4.5)%	(2.7)%	17,859	18,943	(5.7)%	(2.7)%

Number of Electric Customers	As of June 30, 2012	As of June 30, 2011
Residential	1,417,346	1,412,692
Small commercial & industrial	148,837	148,116
Large commercial & industrial	3,107	3,127
Public authorities & electric railroads	9,680	9,661
Total	1,578,970	1,573,596

Electric Revenue	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	% Change	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	% Change
Retail Delivery and Sales(a)						
Residential	$ 393	$ 451	(12.9)%	$ 800	$ 944	(15.3)%
Small commercial & industrial	119	165	(27.9)%	237	334	(29.0)%
Large commercial & industrial	58	67	(13.4)%	111	175	(36.6)%
Public authorities & electric railroads	8	9	(11.1)%	16	20	(20.0)%
Total Retail	578	692	(16.5)%	1,164	1,473	(21.0)%
Other Revenue(b)	57	61	(6.6)%	114	126	(9.5)%
Total Electric Revenues	$ 635	$ 753	(15.7)%	$ 1,278	$ 1,599	(20.1)%

(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, 2012	2011	% Change	Weather-Normal % Change	Six Months Ended June 30, 2012	2011	% Change	Weather-Normal % Change
Retail Delivery and Sales								
Retail sales(a)	6,228	6,561	(5.1)%	(1.1)%	28,655	35,295	(18.8)%	0.8%
Transportation and other	5,835	6,278	(7.1)%	(6.7)%	13,601	15,238	(10.7)%	(9.4)%
Total Gas Deliveries	12,063	12,839	(6.0)%	(3.7)%	42,256	50,533	(16.4)%	(2.2)%

Number of Gas Customers	As of June 30, 2012	2011
Residential	452,478	449,066
Commercial & industrial	41,383	40,956
Total Retail	493,861	490,022
Transportation	888	864
Total	494,749	490,886

Gas revenue	Three Months Ended June 30, 2012	2011	% Change	Six Months Ended June 30, 2012	2011	% Change
Retail Delivery and Sales						
Retail sales(a)	$ 73	$ 82	(11.0)%	$ 295	$ 378	(22.0)%
Transportation and other	7	7	0.0%	17	19	(10.5)%
Total Gas Deliveries	$ 80	$ 89	(10.1)%	$ 312	$ 397	(21.4)%

(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, 2012	Three Months Ended June 30, 2011	Favorable (Unfavorable) Variance	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	Favorable (Unfavorable) Variance
Operating revenues	$ 616	$ 674	$ (58)	$1,312	$1,650	$ (338)
Purchased power and fuel	285	340	55	670	883	213
Revenue net of purchased power and fuel(a)	331	334	(3)	642	767	(125)
Other operating expenses						
Operating and maintenance	161	167	6	356	319	(37)
Depreciation and amortization	71	67	(4)	150	144	(6)
Taxes other than income	47	46	(1)	95	96	1
Total other operating expenses	279	280	1	601	559	(42)
Operating income	52	54	(2)	41	208	(167)
Other income and (deductions)						
Interest expense, net	(34)	(32)	(2)	(75)	(66)	(9)
Other, net	7	6	1	13	13	—
Total other income and (deductions)	(27)	(26)	(1)	(62)	(53)	(9)
Income (loss) before income taxes	25	28	(3)	(21)	155	(176)
Income taxes	9	12	3	(7)	58	65
Net income (loss)	16	16	—	(14)	97	(111)
Preference stock dividends	3	3	—	6	6	—
Net income (loss) on common stock	$ 13	$ 13	$ —	$ (20)	$ 91	$ (111)

(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)

Net income for the three months ended June 30, 2012 compared to the same period in 2011 was relatively consistent. The decrease in net income for the six months ended June 30, 2012 compared to the same period in 2011 was driven primarily by decreased operating revenue net of purchased power and fuel expense related to the accrual of the residential customer rate credit to be provided as a condition of the MDPSC's approval of Exelon's merger with Constellation. The decrease in net income was also driven by increased operating and maintenance expenses, primarily related to BGE's accrual of its portion of the charitable contributions to be provided as a condition of the MDPSC's approval of the merger as well as merger transaction costs. None of the customer rate credit, the charitable contributions, or the transaction costs are recoverable from BGE's customers.

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 338,400 and 278,400 at June 30, 2012 and 2011, respectively, representing 27% and 22% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 62% and 61% of BGE's retail kWh sales for the three and six months ended June 30, 2012, respectively compared to 60% and 57% for the three and six months ended June 30, 2011, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 125,300 and 106,700 at June 30, 2012 and 2011, respectively, representing 19% and 16% of total retail customers, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 68% and 55% of BGE's retail mmcf sales for the three and six months ended June 30, 2012, respectively, compared to 63% and 47% for the three and six months ended June 30, 2011, respectively.

The changes in BGE's operating revenues net of purchased power and fuel expense for the three months ended compared to the same period in 2011, consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Regulatory required programs	$ 2	$ 1	$ 3
Other	(5)	(1)	(6)
Total decrease	$ (3)	$—	$ (3)

The changes in BGE's operating revenues net of purchased power and fuel expense for the six months ended June 30, 2012 compared to the same period in 2011 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Residential customer rate credit(a)	$ (82)	$(31)	$(113)
Regulatory required programs	2	2	4
Commodity margin	(2)	(4)	(6)
Other	(4)	(6)	(10)
Total increase	$ (86)	$(39)	$(125)

(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 impacted 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, 2012 compared to the same period in 2011 consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2012**	**2011**	**Normal**	**From 2011**	**From Normal**
Three Months Ended June 30,					
Heating Degree-Days	402	392	522	2.6%	(23.0)%
Cooling Degree-Days	289	342	246	(15.5)%	17.5%
Six Months Ended June 30,					
Heating Degree-Days	2,275	2,841	2,936	(19.9)%	(22.5)%
Cooling Degree-Days	299	344	249	(13.1)%	20.1%

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

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, 2012 compared to the same period in 2011 was due to the recovery of higher energy efficiency program costs.

Commodity Margin. The commodity margin for both electric and gas revenues decreased during the six months ended June 30, 2012 compared to the same period in 2011. Commodity revenues are affected by the number of customers using competitive suppliers as well as the cost of purchased power and natural gas.

Other. Other revenues decreased during the three and six months ended June 30, 2012 compared to the same period in 2011. Other revenues, which can vary from period to period, include transmission revenues and other miscellaneous revenues such as late payment charge revenues, and all base distribution revenues, which decreased due to lower volumes and customer mix. .

Operating and Maintenance Expense

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	**2011**	**Increase (Decrease)**	**2012**	**2011**	**Increase (Decrease)**
Operating and Maintenance Expense — Baseline	$ 161	$ 167	$ (6)	$ 356	$ 319	$ 37
Operating and Maintenance Expense — Regulatory Required Programs(a)	—	—	—	—	—	—
Total Operating and Maintenance Expense	161	167	(6)	356	319	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, 2012 compared to the same periods in 2011, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Baseline		
Charitable contributions accrual(a)	$ —	$ 28
Storm costs deferral(b)	—	16
Merger transaction costs(a)	(7)	5
Labor, other benefits, contracting and materials	(1)	(7)
Pension Benefits	1	2
Storm-related costs(c)	3	(11)
Other	(2)	4
	(6)	37
Regulatory Required Programs		
SOS	—	—
(Decrease) increase in operating and maintenance expense	$ (6)	$ 37

(a) The charitable contribution accrual and merger transaction costs are not recoverable from BGE's customers.
(b) During the first quarter of 2011, the MDPSC issued a comprehensive rate order permitting the deferral of incremental distribution service restoration expenses associated with 2010 storms as a regulatory asset.
(c) On June 29, 2012, a "Derecho" storm caused extensive damage to BGE's electric distribution system and created power outages that lasted multiple days. As a result, BGE incurred $4 million of incremental costs, of which $1 million is capital costs, during the three and six months ended June 30, 2012. This amount compares to $14 million of incremental expenses incurred during the first quarter of 2011. The total incremental cost of the Derecho storm, most of which was incurred after June 30, 2012, is estimated to be $62 million, of which $20 million are capital costs.

Depreciation and Amortization

The increase in depreciation and amortization expense for the three and six months ended June 30, 2012 compared to the same periods in 2011 was primarily due to higher plant balances. Additionally, depreciation and amortization expense includes amortization expense related to energy efficiency and demand response programs which is fully offset in revenues above.

Taxes Other Than Income

Taxes other than income remained relatively consistent for the three and six months ended June 30, 2012 compared to the same periods in 2011.

Interest Expense, Net

The increase in interest expense, net for the three and six months ended June 30, 2012 compared to the same periods in 2011 was primarily due to interest recorded on prior year tax liabilities as well as higher outstanding debt balances.

Other, Net

Other, net remained consistent for the three and six months ended June 30, 2012 compared to the same periods in 2011. See Note 17 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 36.0% and 42.9% for the three months ended June 30, 2012 and 2011, respectively, and 33.3% and 37.4% for the six months ended June 30, 2012 2011, respectively. See Note 10 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, 2012	Three Months Ended June 30, 2011	% Change	Weather-Normal % Change	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)								
Residential	2,663	2,751	(3.2)%	n.m	5,865	6,276	(6.5)%	n.m
Small commercial & industrial	4,035	4,156	(2.9)%	n.m	7,816	8,073	(3.2)%	n.m
Large commercial & industrial	637	617	3.2%	n.m	1,259	1,154	9.1%	n.m
Public authorities & electric railroads	48	108	(55.6)%	n.m	96	209	(54.1)%	n.m
Total Electric Retail	7,383	7,632	(3.3)%	n.m	15,036	15,712	(4.3)%	n.m

Number of Electric Customers	As of June 30, 2012	As of June 30, 2011
Residential	1,115,107	1,115,989
Small commercial & industrial	119,338	118,274
Large commercial & industrial	5,432	5,443
Public authorities & electric railroads	296	326
Total	1,240,173	1,240,032

Electric Revenue	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	% Change	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	% Change
Retail Delivery and Sales(a)						
Residential	$ 295	$ 326	(9.5)%	$ 560	$ 749	(25.2)%
Small commercial & industrial	149	161	(7.5)%	298	328	(9.1)%
Large commercial & industrial	10	14	(28.6)%	20	27	(25.9)%
Public authorities & electric railroads	7	7	0.0%	15	15	0.0%
Total Retail	461	508	(9.3)%	893	1,119	(20.2)%
Other Revenue	57	57	0.0%	114	115	(0.9)%
Total Electric Revenues	$ 518	$ 565	(8.3)%	$ 1,007	$ 1,234	(18.4)%

(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.

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BGE Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	Three Months Ended June 30, 2012	2011	% Change	Weather-Normal % Change	Six Months Ended June 30, 2012	2011	% Change	Weather-Normal % Change
Retail Delivery and Sales(b)								
Retail sales	15,535	14,407	7.8%	n.m.	49,466	56,485	(12.4)%	n.m.
Transportation and other	4,854	4,028	20.5%	n.m.	10,295	9,582	7.4%	n.m.
Total Gas Deliveries	20,389	18,435	10.6%	n.m.	59,761	66,067	(9.5)%	n.m.

Number of Gas Customers	As of June 30, 2012	2011
Residential	610,073	608,945
Commercial & industrial	44,011	43,953
Total	654,084	652,898

Gas revenue	Three Months Ended June 30, 2012	2011	% Change	Six Months Ended June 30, 2012	2011	% Change
Retail Delivery and Sales						
Retail sales	$ 84	$ 87	(3.4)%	$ 272	$ 359	(24.2)%
Transportation and other(b)	14	22	(36.4)%	33	57	(42.1)%
Total Gas Deliveries	$ 98	$ 109	(10.1)%	$ 305	$ 416	(26.7)%

(b) Transportation and other gas revenue includes off-system revenue of 4,854 mmcfs ($12M) and 4,028 mmcfs ($19M) for the three months ended June 30, 2012 and 2011, respectively, and 10,295 mmcfs ($29M) and 9,582 mmcfs ($51M) for the six months ended June 30, 2012 and 2011, respectively.

Liquidity and Capital Resources

Exelon and Generation 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. Exelon and Generation prior year activity is unadjusted for the effects of the merger. BGE activity presented below includes its activity for the six months ended June 30, 2012 and 2011.

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 $2.9 billion, $5.6 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. The Registrants' revolving credit facilities expire between October 2013 and March 2017. The bilateral facilities at Exelon and Generation have expirations that range from September 2013 through March 2016. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to 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 9 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 to wholesale 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, and their ability to achieve operating cost reductions. See Notes 4 and 16 of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

Pension and Other Postretirement Benefits

The funded status of the pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations of the plans. The funded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

For financial reporting purposes, the unfunded status of Exelon's plans is updated annually, at December 31, unless there is a significant event such as a major plan amendment, settlement, or curtailment. Effective March 12, 2012, Exelon became the sponsor of all of Constellation's defined benefit pension and other postretirement benefit plans. As a result of employee severances related to the merger, a curtailment was triggered for certain legacy Constellation pension and other postretirement benefit plans in the second quarter of 2012. Accordingly, the benefit obligation and plan assets for those plans were remeasured using assumptions as of June 30, 2012. The discount rates used to calculate the curtailed pension and other postretirement benefit plan obligations as of June 30, 2012 were 3.97% and 3.98%, respectively.

In order to provide additional information about the potential impact of current financial market conditions on the plans, Exelon has estimated the unfunded status of the pension and other postretirement benefit plans at June 30, 2012 by updating the most significant assumptions affecting plan obligations and assets, which are the discount rate and current year's plan asset investment performance. The discount rates for legacy Exelon's pension and other postretirement benefit plans were 4.15% and 4.23%, respectively, at June 30, 2012. The discount rates for legacy Constellation's pension and other postretirement benefit plans were 3.97% and 3.98%, respectively, at June 30, 2012, which are consistent with the discount rates used above in connection with the curtailment remeasurement of certain legacy Constellation plans. Additionally, Exelon's pension and funded other postretirement benefit plans experienced actual asset returns of approximately 5.70% and 5.40%, respectively, for the six months ended June 30, 2012.

Based on these assumptions, Exelon has estimated the unfunded status of the pension and other postretirement benefit plans at June 30, 2012 to be $3,545 million and $3,020 million, respectively, representing a funded status percentage of 79% and 37%, respectively. The unfunded status of Exelon's pension and other postretirement benefit plans increased $1,309 million and $755 million, respectively, since December 31, 2011 primarily due to the acquisition of Constellation's pension and other postretirement benefit plans, growth in benefit obligations as a result of service and interest cost, a decrease in Exelon's discount rates and demographic losses based on Exelon's updated valuation, partially offset by favorable asset returns as of June 30, 2012. Legacy Constellation asset returns are for the period after March 12, 2012.

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 $83 million to its qualified pension plans in 2012, of which Generation, ComEd and PECO will contribute $51 million, $9 million and $12 million, respectively. Legacy Constellation's 2011 pension contributions included an acceleration of estimated calendar year 2012 contributions. Therefore, BGE does not anticipate any qualified pension contributions in 2012. 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 $67 million in 2012, of which Generation, ComEd, PECO and BGE will make payments of $9 million, $14 million, $1 million and $1 million, respectively.

Management has estimated its future pension contributions at June 30, 2012, incorporating updated projected discount rates and anticipated employee severances as a result of the merger. The estimated pension contributions summarized below include ERISA minimum-required contributions, contributions necessary to avoid benefit restrictions and at-risk status, and payments related to the non-qualified pension plans; these estimates do not include any incremental contributions Exelon may elect to make in these future periods. 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 will be applied in 2012 while others take effect in 2013. The estimated impacts of the law are reflected in the projected pension contributions below.

	2013	2014	2015	2016	2017	Cumulative
Estimated pension contributions	$50	$70	$285	$840	$795	$ 2,040

To the extent interest rates continue to 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 projected 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 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 2012, 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 $318 million in 2012, of which Generation, ComEd, PECO and BGE expect to contribute $132 million, $116 million, $34 million and $14 million, respectively. This total excludes $4 million in 2012 other postretirement benefit plan contributions by BGE prior to the closing of Exelon's merger with Constellation on March 12, 2012. Based on the current funding strategy, the Registrants expect to contribute an aggregate of approximately $260 million — $305 million annually from 2013 to 2017 to the other postretirement benefit plans.

Tax Matters

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

- In the third quarter of 2010, Exelon and IRS Appeals reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion and CTC positions. Under the terms of the preliminary agreement, Exelon estimates that the IRS will assess tax and interest of approximately $300 million in 2012 for the years for which there is a resulting tax deficiency. In order to stop additional interest from accruing on the expected assessment, Exelon made a payment in December 2010 to the IRS of $302 million. Further, Exelon expects to receive additional tax refunds of approximately $350 million between 2013 and 2014, including the refund resulting from the nuclear decommissioning trust fund special transfer tax deduction described in Note 11 of the Exelon 2011 Form 10-K of which approximately $30 million, $350 million and $30 million would be received by Generation, ComEd and PECO, respectively, and the remainder paid by Exelon. Exelon and IRS Appeals have failed to reach a settlement with respect to the like-kind exchange position and the related substantial understatement penalty. See Note 10 of the Combined Notes to Consolidated Financial Statements for additional information regarding potential cash flows impacts of a fully successful IRS challenge to Exelon's like-kind exchange position.
- The Tax Relief Act of 2010, enacted into law on December 17, 2010, includes provisions accelerating the depreciation of certain property for tax purposes. Qualifying property placed into service after September 8, 2010, and before January 1, 2012, was eligible for 100% bonus depreciation. Additionally, qualifying property placed into service during 2012 is eligible for 50% bonus depreciation. These provisions are expected to generate approximately $650 million of cash for Exelon in 2012. The cash generated is an acceleration of tax benefits that Exelon would have otherwise received over 20 years. Additionally, while the capital additions at ComEd, PECO and BGE generally increase future revenue requirements, the bonus depreciation associated with these capital additions will partially mitigate any future rate increases through the ratemaking process.
- 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.
- Exelon currently anticipates that the IRS will issue guidance in 2012 on the appropriate tax treatment of repair costs for gas distribution assets. If the guidance is issued consistent with Exelon's expectation and PECO and BGE choose to change to the newly prescribed method, it would likely result in an earnings and cash tax benefit at PECO. The effect at BGE is expected to be immaterial. See Note 10 — Income Taxes for discussion regarding the regulatory treatment of PECO's potential tax benefits from the application of the method change prescribed in the 2010 natural gas distribution rate case settlement.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the six months ended June 30, 2012 and 2011:

	Six Months Ended June 30,		
	2012	2011	Variance
Net income	$ 490	$ 1,290	$ (800)
Add (subtract):			
Non-cash operating activities(a)	2,688	2,295	393
Pension and other postretirement benefit contributions	(90)	(2,089)	1,999
Income taxes	259	691	(432)
Changes in working capital and other noncurrent assets and liabilities(b)	(961)	(718)	(243)
Option premiums (paid) received, net	(108)	38	(146)
Counterparty collateral received (posted), net	451	(494)	945
Net cash flows provided by operations	$2,729	$ 1,013	$1,716

(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 earnings and 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, 2012 and 2011 by Registrant were as follows:

	Six Months Ended June 30,	
	2012	2011
Exelon	$ 2,729	$ 1,013
Generation	1,866	1,076
ComEd	722	71
PECO	409	359
BGE	369	473

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, 2012 and 2011 were as follows:

Generation

- During the six months ended June 30, 2012 and 2011, Generation had net receipts (payments) of counterparty collateral of $443 million and $(525) million, respectively. Net receipts (payments) during the six months ended June 30, 2012 and 2011 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 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, 2012 and 2011, Generation had net (payments) collections of approximately $(108) million and $38 million, respectively, related to the 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.
- During the six months ended June 30, 2012 and 2011, Generation's accounts receivable from PECO increased (decreased) $21 million and $(206) million, respectively. The decrease for the six months ended June 30, 2011 was due to the expiration of the PECO PPA in December 2010.

ComEd

- During the six months ended June 30, 2012 and 2011, 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 $(10) million and $(15) million, respectively. During the six months ended June 30, 2012 and 2011, ComEd's payables to other energy suppliers for energy purchases increased (decreased) by $22 million and $(6) million, respectively.
- During the six months ended June 30, 2012 and 2011, ComEd received $7 million and $28 million, respectively, of incremental cash collateral from PJM due to seasonal variations in its energy transmission activity levels and merger related allocation of unsecured credit. ComEd's collateral

posted with PJM decreased during the six months ended June 30, 2012 due to a $14 million decrease for seasonal variations, lower market capacity and energy prices and customer load migration, partially offset by a $7 million increase for the reallocation of the $50 million unsecured credit level afforded to Exelon amongst a greater number of subsidiaries following the merger with Constellation. As of June 30, 2012 and 2011, ComEd had $84 million and $125 million, respectively, of collateral remaining at PJM.

PECO

- During the six months ended June 30, 2012 and 2011, PECO’s payables to Generation for energy purchases increased (decreased) by $21 million and $(206) million, respectively, and payables to other electric and gas suppliers for energy purchases (decreased) increased by $(31) million and $88 million, respectively.

BGE

- During the six months ended June 30, 2012 and 2011, BGE’s payables to Generation for energy purchases increased (decreased) $2 million and $(10) million, respectively, and payables to other electric and gas suppliers for energy purchases (decreased) by $(5) million and $(34) million, respectively.
- During the six months ended June 30, 2012 and 2011, BGE’s accrued expenses (decreased) $(50) million due to the reversal of an accrued uncertain tax position and increased $58 million due to the accrual of an uncertain tax position, respectively.

Cash Flows from Investing Activities

Cash flows used in investing activities for the six months ended June 30, 2012 and 2011 by Registrant were as follows:

	Six Months Ended June 30,	
	2012	2011
Exelon	$(1,984)	$(2,074)
Generation	(1,284)	(1,388)
ComEd	(567)	(473)
PECO	(157)	(371)
BGE	(284)	(279)

Capital expenditures by Registrant for the six months ended June 30, 2012 and 2011 and projected amounts for the full year 2012 are as follows:

	Projected Full Year	Six Months Ended June 30,	
	2012	2012	2011
Exelon	$ 6,226	$2,816	$1,985
Generation(a)	3,914	1,820	1,270
ComEd(b)	1,282	585	495
PECO	433	179	209
BGE	542	282	283
Other(c)	55	30	11

(a) Includes nuclear fuel.

(b) The projected capital expenditures include approximately $200 million in incremental spending related to ComEd's 2012 investment plan filed with the ICC on January 6, 2012. Pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over the next ten years to modernize and storm-harden its distribution system and to implement smart grid technology.
(c) Other primarily consists of corporate operations and BSC.

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

Generation

Approximately 33% and 30% of the projected 2012 capital expenditures at Generation are for investments in renewable energy generation, including Antelope Valley and Exelon Wind construction costs, and the acquisition of nuclear fuel, respectively. The remaining amounts primarily reflect additions and upgrades to existing facilities including material condition improvements during nuclear refueling outages. Also included in the projected 2012 capital expenditures are a portion of the costs of a series of planned power uprates across Generation's nuclear fleet. A review of the LaSalle Extended Power Uprate was performed this quarter and the completion of the project was deferred by two years, primarily as a result of market conditions. See "EXELON CORPORATION — Executive Overview," for more information on nuclear uprates.

On August 8, 2012, a subsidiary of Generation reached an agreement to sell three Maryland generating stations and associated assets to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC. Generation expects to receive proceeds of approximately $400 million less transaction costs of approximately $20 million at or around closing of the transaction in the fourth quarter of 2012. In addition, under the terms of the agreement, Generation will make cash payments of approximately $25 million to Raven Power Holdings LLC over a twelve-month period beginning in June 2014. The sale will generate approximately $205 million of cash tax benefits, of which $135 million will be realized in periods through 2013 with the balance to be received in later years. Therefore, Generation expects net after-tax cash sale proceeds of approximately $435 million in 2012, approximately $80 million in 2013 and approximately $45 million in 2014 and subsequent years. Net after-tax cash sales proceeds for 2012 are approximately $170 million lower than prior projections, of which approximately $70 million will be reversed in 2013. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on the sale.

ComEd, PECO and BGE

Approximately 82%, 70% and 71% of the projected 2012 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. The remaining amounts are for capital additions to support new business and customer growth, which for ComEd includes capital expenditures related to smart grid/smart meter technology required under EIMA, and for PECO and BGE includes capital expenditures related to their smart meter program and SGIG project, net of DOE expected reimbursements. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

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 2012. 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 2012 capital expenditures above reflect capital spending for remediation to be completed in 2012.

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 4 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, 2012 and 2011 by Registrant were as follows:

	Six Months Ended June 30,	
	2012	2011
Exelon	$ (412)	$ 11
Generation	(148)	(35)
ComEd	(360)	446
PECO	(174)	(191)
BGE	(81)	(123)

Debt

See Note 9 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, 2012 and 2011 by Registrant were as follows:

	Six Months Ended June 30,	
	2012	2011
Exelon	$ 824	$ 695
Generation	891	—
ComEd	85	150
PECO	174	186
BGE	6	91(a)

(a) Dividends on common stock for $85 million were paid to Constellation for the six months ended June 30, 2011.

Second Quarter 2012 Dividend

On January 24, 2012, the Exelon Board of Directors declared a second quarter 2012 regular quarterly dividend of $0.525 per share on Exelon's common stock contingent on the merger with Constellation. Based on the effective date of the merger, shareholders received two separate dividend payments totaling $0.525 per share as follows:

- The first of the dividend payments was pro-rated, with shareholders of record as of the end of day before the effective date of the merger (March 12, 2012) receiving $0.00583 per share per day for the period from and including February 16, 2012, the day after the record date for the previous dividend, through and including the day before the effective date of the merger. This portion of the dividend, totaling $97 million, was paid on April 10, 2012.
- The second of the dividend payments was also pro-rated, with all Exelon shareholders, including the former Constellation shareholders, of record at the end of the day on May 15, 2012, receiving $0.00583

per share per day for the period from and including the effective date of the merger (March 12, 2012) through and including May 15, 2012. This portion of the dividend, totaling approximately $323 million, was paid on June 8, 2012.

Third Quarter 2012 Dividend

On July 24, 2012, the Exelon Board of Directors declared a regular quarterly dividend payable on September 10, 2012 of $0.525 per share on Exelon's common stock.

Short-Term Borrowings

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. During the six months ended June 30, 2011, Exelon issued $140 million of commercial paper.

Contributions from Parent/Member

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. There were no contributions from Parent/Member (Exelon) during the six months ended June 30, 2011.

Other

For the six months ended June 30, 2012, other financing activities primarily consists of expenses paid related to the replacement of the Registrants' credit facilities. See Note 9 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 $10.7 billion in aggregate total commitments of which $8.0 billion was available as of June 30, 2012, and of which no financial institution has more than 10% of the aggregate commitments. Exelon, Generation, ComEd, PECO and BGE had access to the commercial paper market during the second quarter of 2012 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 2011 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, 2012, it would have been required to provide incremental collateral of $2.4 billion, which is well within its current available credit facility capacities of $3.8 billion, which includes 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, 2012, it would have been required to provide incremental collateral of $218 million, which is well within its current available credit facility capacity of $821 million, which takes into account commercial paper borrowings as of June 30, 2012. If PECO lost its investment grade credit rating as of June 30, 2012, it would not have been required to provide collateral pursuant to PJM's credit policy and could have been required to provide collateral of $36 million related to its natural gas procurement contracts, which, in the aggregate, is well within PECO's current available credit facility capacity of $599 million. If BGE lost its investment grade credit rating as of June 30, 2012, it would have been required to provide collateral of $3 million pursuant to PJM's credit policy and could have been required to provide collateral of $54 million related to its natural gas procurement contracts, which, in the aggregate, is well within BGE's current available credit facility capacity of $599 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 9 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, 2012:

Commercial Paper Programs

Commercial Paper Issuer	Maximum Program Size(a)	Outstanding Commercial Paper at June 30, 2012	Average Interest Rate on Commercial Paper Borrowings for the six months ended June 30, 2012
Exelon Corporate(b)	$ 500	$ 188	0.44%
Generation	5,600	—	0.45%
ComEd	1,000	178	0.51%
PECO	600	—	—
BGE	600	—	—

(a) Equals aggregate bank commitments under revolving credit agreements and bilateral credit agreements. See discussion and table below for items affecting effective program size.

(b) The Exelon $1.5 billion revolver and the Exelon bilateral facilities assumed by Exelon from Constellation in connection with the merger are not currently used to support the Exelon commercial paper program.

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, 2012		Average Interest Rate on Facility Borrowings for the Six Months Ended June 30, 2012
					Actual	To Support Additional Commercial Paper	
Exelon Corporate(b)	Syndicated Revolver	$ 2,000	$ —	$ 43	$1,957	$ 498	—
Exelon Corporate(b)	Bilateral / Commodity Linked	900	—	573	327	—	—
Generation	Syndicated Revolver	5,300	—	1,455	3,845	3,845	—
Generation	Bilateral	300	—	299	1	1	—
ComEd	Syndicated Revolver	1,000	—	1	999	821	—
PECO	Syndicated Revolver	600	—	1	599	599	—
BGE	Syndicated Revolver	600	—	1	599	599	—

(a) Excludes $118 million of credit facility agreements arranged with minority and community banks at Generation, ComEd and PECO. These facilities, which expire in October 2012, are solely utilized to issue letters of credit. See Note 9 of the Combined Notes to the Consolidated Financial Statements for further information.

(b) The Exelon $1.5 billion revolver and the Exelon supplemental facilities are not currently used to support the Exelon commercial paper program.

A subsidiary of Generation also has a three-year senior secured credit facility associated with certain solar projects. The amount committed under the facility is $150 million, which may be increased up to a total amount of $200 million at the subsidiary's request with additional commitments by the lenders. Obligations under this facility are secured by the equity interests in the subsidiary and the entities that own the solar projects as well as the assets of the subsidiary of each project entity and are guaranteed by Generation and the project entities. As of June 30, 2012, the outstanding loan balance was $124 million.

CEU, a subsidiary of Generation, has a reserve-based lending facility that supports the upstream gas operations. The borrowing base committed under the facility is $150 million and can grow up to $500 million if the assets support a higher borrowing base and if CEU is able to obtain additional commitments from lenders. The facility expires in July 2016 and any borrowings under this facility are secured by the upstream gas properties. As of June 30, 2012, the outstanding loan balance was $37 million.

Borrowings under each revolving credit agreement bear interest at a rate selected by the borrower based upon either the prime rate or at a fixed rate for a specified period based upon a LIBOR-based rate. The agreements also provide for adders based upon the credit rating of the borrower. Under the ComEd agreement executed on March 28, 2012, adders of up to 65 basis points for prime-based borrowings and 165 basis points for LIBOR-based borrowings may be added based upon ComEd's credit rating. At June 30, 2012, ComEd's adder was 27.5 basis points for prime based borrowings and 127.5 basis points for LIBOR-based borrowings.

Under the Exelon and Generation bilateral and commodity-linked credit agreements, Exelon and Generation pay a facility fee, payable quarterly at a rate per annum equal to a specified facility fee rate on the total amount of the credit facility regardless of usage.

Each revolving credit agreement for Exelon, Generation, ComEd and PECO 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, 2012:

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

At June 30, 2012, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO
Interest coverage ratio	11.70	19.43	6.78	8.15

The BGE credit agreement contains a provision requiring BGE to maintain a Debt to Capitalization ratio equal to or less than 65%. As of June 30, 2012, the BGE Debt to Capitalization ratio as defined in its credit agreement was 44%.

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 facilities.

On July 18, 2012, Exelon Corporate, Generation, PECO and BGE launched transactions to amend and extend their unsecured revolving credit facilities, with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million respectively. The amended credit facilities will reflect current market pricing and the extension will bring maturities out to five years from the close of the transactions. The transactions are expected to close and become effective in August 2012. 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. The maturity of the $1.5 billion Constellation Credit Agreement will be amended to December 31, 2012.

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 8 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, 2012, in addition to the net contribution or borrowing as of June 30, 2012, are presented in the following table:

Contributed (borrowed) as of June 30, 2012	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Generation	$ —	$ 258	$ —
PECO	309	—	64
BSC	—	206	(64)
Exelon Corporate	44	N/A	—

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; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the values 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 allocations in accordance with Generation's NDT fund investment policy. With regard to equity securities, Generation's investment policy establishes limits on the concentration of equity holdings in any one company and also in any one industry. With regard to fixed-income securities, Generation's investment policy limits the concentrations of the types of bonds that may be purchased for the trust funds and also requires a minimum percentage of the portfolio to have investment grade ratings (minimum credit quality ratings of "Baa3" by Moody's, "BBB-" by S&P and "BBB-" by Fitch Ratings) while requiring that the overall portfolio maintain a minimum credit quality rating of "A2". See Note 11 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. As of June 30, 2012, Exelon, Generation, ComEd, PECO and BGE each had a current shelf registration statement effective with the SEC that provides for the sale of unspecified amounts of securities The ability of each Registrant to sell securities off its 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 February 27, 2012, ComEd received $1.3 billion in long-term debt refinancing authority from the ICC. As of June 30, 2012, ComEd had $1.4 billion available in long-term debt refinancing authority and $456 million available in new money long-term debt financing authority from the ICC. PECO had $1.9 billion available in long-term debt financing authority from the PAPUC and BGE had $2.0 billion available in long-term financing authority from the MDPSC. On August 1, 2012, PECO filed an application for long-term financing authority with the PAPUC for an amount up to $2.5 billion, which will be effective over a three-year period from January 1, 2013 through December 31, 2015. PECO anticipates receiving the approval from the PAPUC in the fourth quarter of 2012.

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As of June 30, 2012, 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, 2012, 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 16 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 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 2011 Form 10-K and Constellation's and BGE's 2011 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' 2011 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 purchase and sale of electricity, fossil fuel, and other commodities.

Generation

Normal Operations and Hedging Activities. Electricity available from Generation's owned, contracted or investments in generation supply in excess of Generation's obligations to customers, including 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 physical contracts as well as financial 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, including the ComEd financial swap contract, will occur during 2012 through 2014. Generation's energy contracts are accounted for under the accounting guidance for derivatives as further discussed in Note 8 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, 2012, the percentage of expected generation hedged was 99%-102%, 79%-82% and 46%-49% for 2012, 2013 and 2014, 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 excluding owned generation to be retired or sold in 2012. 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 non-trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on June 30, 2012 market conditions and hedged position would be a decrease in pre-tax net income of approximately $18 million, $224 million and $609 million, respectively, for 2012, 2013 and 2014, including coal units to be divested through September 2012. Power prices 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 4,248 GWhs and 6,077 GWhs for the three and six months ended June 30, 2012, respectively, and 1,496 GWhs and 2,829 GWhs for the three and six months ended June 30, 2011, respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Proprietary trading portfolio activity for the six months ended June 30, 2012 resulted in pre-tax gains of $11 million due to net mark-to-market gains of $46 million and realized losses of $35 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 $1.6 million during the quarter. 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, 2012 of $3,596 million, Generation has not segregated proprietary trading activity in the following tables.

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 56% of Generation's uranium concentrate requirements from 2012 through 2016 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 16 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 will be entitled to receive full cost recovery in rates. The change in fair value each period is recorded by ComEd with an offset to a regulatory asset or liability. This financial swap contract between Generation and ComEd expires on May 31, 2013.

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.

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. Delivery under these contracts begins in June 2012. 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 4 and 8 of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

PECO

PECO has block contracts and full requirements contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Program, which is further discussed in Note 4 of the Combined Notes to Consolidated Financial Statements. PECO's full requirements contracts and block contracts, which are considered derivatives, qualify for the normal purchases and normal sales exception under current derivative authoritative guidance. Under the DSP Program, 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. See Note 8 of the Combined Notes to Consolidated Financial Statements for additional information on these contracts.

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. See Note 8 of the Combined Notes to Consolidated Financial Statements for additional information on these contracts.

Trading and Non-Trading Marketing Activities. The following detailed presentation of Exelon's, Generation's, ComEd's and BGE'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).

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The following table provides detail on changes in Exelon's, Generation's, ComEd's and BGE's mark-to-market net asset or liability balance sheet position from December 31, 2011 to June 30, 2012. 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 hedging activities that are recorded in accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts. See Note 8 of the Combined Notes to Consolidated Financial Statements for additional information on the cash flow hedge gains and losses included within accumulated OCI and the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of June 30, 2012 and December 31, 2011.

	Generation	ComEd	BGE	Intercompany Eliminations(g)	Exelon
Total mark-to-market energy contract net assets (liabilities) at December 31, 2011(a)	$ 1,648	$ (800)	$ —	$ —	$ 848
Contracts Acquired at merger date(h)	140				140
Total change in fair value during 2012 of contracts recorded in result of operations	163	—	—	15	178
Reclassification to realized at settlement of contracts recorded in results of operations	148	—	—	—	148
Ineffective portion recognized in income(b)	(5)	—	—	—	(5)
Reclassification to realized at settlement from accumulated OCI(c)	(722)	—	—	319	(403)
Effective portion of changes in fair value — recorded in OCI(d)	719	—	—	(146)	573
Changes in fair value — energy derivatives(e)	—	183	—	(188)	(5)
Changes in collateral	(443)	—	—	—	(443)
Changes in net option premium paid/(received)	108	—	—	—	108
Other income statement reclassifications(f)	(64)	—	—	—	(64)
Intercompany Elimination of Existing Derivative Contracts with Constellation	(103)	—	—	—	(103)
Other balance sheet reclassifications	1	—	—	—	1
Total mark-to-market energy contract net assets (liabilities) at June 30, 2012(a)	$ 1,590	$ (617)	$ —	$ —	$ 973

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

(b) For Generation, includes $5 million of changes in cash flow hedge ineffectiveness, of which none was related to Generation's financial swap contract with ComEd.

(c) For Generation, includes $319 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, 2012.

(d) For Generation, includes $146 million of gains related to the changes in fair value of the five-year financial swap with ComEd for the six months ended June 30, 2012.

(e) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of June 30, 2012, ComEd recorded a $617 million regulatory asset related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. As of June 30, 2012, this included $121 million change in fair value and $319 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, 2012, ComEd also recorded a $5 million increase in fair value associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.

(f) Includes $64 million of option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations for the six months ended June 30, 2012.

(g) Amounts related to the five-year financial swap between Generation and ComEd are eliminated in consolidation. Effective prior to the merger, the five-year financial swap 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.

(h) For Generation, includes $660 million of collateral paid to counterparties.

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Fair Values. The following tables present maturity and source of fair value of the Registrants mark-to-market energy 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). Second, the tables show the maturity, by year, of the Registrants' energy contract net assets (liabilities), giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 7 of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2012	2013	2014	2015	2016	2017 and Beyond	Total Fair Value
Normal Operations, economic hedge contracts(a)(b):							
Actively quoted prices (Level 1)	$ (7)	$ (11)	$(116)	$ (48)	$ 5	$ 2	$ (175)
Prices provided by external sources (Level 2)	91	297	334	116	17	(2)	853
Prices based on model or other valuation methods (Level 3)(c)	61	107	72	43	25	(13)	295
Total	$145	$393	$ 290	$ 111	$47	$ (13)	$ 973

(a) Mark-to-market gains and losses on other non-trading hedge and trading derivative contracts are recorded in results of operations.
(b) Amounts are shown net of allocated collateral paid to and received from counterparties of $323 million at June 30, 2012.
(c) Includes ComEd's net assets associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2012	2013	2014	2015	2016	2017 and Beyond	Total Fair Value
Normal Operations, economic hedge contracts(a)(b) :							
Actively quoted prices (Level 1)	$ (7)	$ (11)	$(116)	$ (48)	$ 5	$ 2	$ (175)
Prices provided by external sources (Level 2)	91	297	334	116	17	(2)	853
Prices based on model or other valuation methods (Level 3)	367	335	88	57	38	27	912
Total	$451	$621	$ 306	$125	$60	$ 27	$ 1,590

(a) Mark-to-market gains and losses on other non-trading hedge and trading derivative contracts are recorded in results of operations. Amounts include a $506 million gain associated with the five-year financial swap with ComEd.
(b) Amounts are shown net of allocated collateral paid to and received from counterparties of $323 million at June 30, 2012.

ComEd

	Maturities Within						
	2012	2013	2014	2015	2016	2017 and beyond	Total Fair Value
Prices based on model or other valuation methods(a)	$(306)	$(228)	$(16)	$(14)	$(13)	$ (40)	$ (617)

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

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

The Registrants are exposed to credit-related losses in the event of non-performance by counterparties with whom they enter into derivative instruments. The credit exposure of derivative contracts, before collateral and netting, is represented by the fair value of contracts at the reporting date. See Note 8 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, 2012. 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 and NYMEX, ICE and the 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 $61 million, $59 million and $11 million, respectively. See Note 21 of the Exelon 2011 Form 10-K for further information.

Rating as of June 30, 2012	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	$ 2,523	$ 802	$ 1,721	—	$ —
Non-investment grade	88	41	47	—	—
No external ratings					
Internally rated — investment grade	552	16	536	1	286
Internally rated — non-investment grade	64	7	57	—	—
Total	$ 3,227	$ 866	$ 2,361	1	$ 286

	Maturity of Credit Risk Exposure			
Rating as of June 30, 2012	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 1,933	$ 463	$ 127	$ 2,523
Non-investment grade	64	24	—	88
No external ratings				
Internally rated — investment grade	335	187	30	552
Internally rated — non-investment grade	64	—	—	64
Total	$ 2,396	$ 674	$ 157	$ 3,227

Net Credit Exposure by Type of Counterparty	As of June 30, 2012
Investor-owned utilities, marketers and power producers	$ 1,091
Energy cooperatives and municipalities	775
Financial institutions	406
Other	89
Total	$ 2,361

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 2011 Annual Report on Form 10-K.

See Note 8 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 2011 Annual Report on Form 10-K.

See Note 8 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 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS of BGE's 2011 Annual Report on Form 10-K.

See Note 8 of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

Collateral (Generation, ComEd and PECO)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the purchase and sale 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 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 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 at the time of the demand. 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.

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.

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As of June 30, 2012, Generation had $697 million cash collateral deposit payments being held by counterparties and Generation was holding $1,007 million of cash collateral deposits received from counterparties, of which $323 million in net cash collateral deposits was offset against mark-to-market assets and liabilities. As of June 30, 2012, $13 million of cash collateral received was not offset against net derivative positions because it was not associated with energy-related derivatives. See Note 16 of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of June 30, 2012, 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 $20 million in the form of cash and letters of credit for both annual and long-term renewable energy contracts.

PECO

As of June 30, 2012, PECO was not required to post, nor does it hold, collateral under its energy supply and natural gas procurement contracts. See Note 8 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, 2012, 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 8 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, New York ISO, California ISO, MISO, Southwest Power Pool, Inc., 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 the Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on NYMEX, ICE and the Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and the Nodal exchange are significantly collateralized and have limited counterparty credit risk.

Long-Term Leases (Exelon)

Exelon's consolidated balance sheets, as of June 30, 2012, included a $670 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 approximately $1.5 billion, less unearned income of $822 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms which are set at prices above the then expected fair market value of the plants. If the lessees do not exercise the fixed purchase options, the lessees return the leasehold interests to Exelon and Exelon has the ability to require the lessees to arrange a service contract with a third party for a period following the lease term. In any event, Exelon is subject to residual value risk to the extent the fair value of the assets are less than the residual value. This risk is mitigated by the fair value of the fixed payments under the service contract. The term of the service contract, however, 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, including letters of credit, surety bonds and credit swaps. Management regularly evaluates the credit worthiness of Exelon's counterparties to these long-term leases. Since 2008, the entity providing the credit enhancement for one of the lessees did not meet the credit rating requirements of the lease. Consequently, Exelon has indefinitely extended a waiver and reduction of the rating requirement, which Exelon may terminate by giving 90 days notice to the lessee. Exelon monitors the continuing credit quality of the credit enhancement party.

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 use interest rate swaps when deemed appropriate. Additionally, the Registrants may use forward-starting interest rate swaps and treasury rate locks to lock in interest rate levels in anticipation of future financings. These strategies are employed to manage interest rate risk. At June 30, 2012, Exelon had $800 million of notional amounts of fixed-to-floating interest rate swaps outstanding, of which $650 million are designated as fair value hedges and $150 million are marked to market. Generation had $463 million of notional amounts of cash flow hedges outstanding. Assuming the fair value and cash flow hedges are effective, a hypothetical 50 bps increase in the interest rates associated with variable-rate debt and interest rate swaps would result in less than a $ 2 million decrease in each of Exelon's, Generation's and PECO's pre-tax earnings for the six months ended June 30, 2012. This calculation holds all other variables constant and assumes only the discussed changes in interest rates.

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, 2012, 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 $353 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 2012, 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, 2012, 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. However, there have been no changes in internal control over financial reporting that occurred during the second quarter of 2012, other than changes resulting from the Constellation merger and BGE's implementation of the Customer Care and Billing (CC&B) system as discussed below, 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.

On March 12, 2012, the merger between Exelon and Constellation closed. Exelon is currently in the process of integrating Constellation's operations, processes, and internal controls. See Note 3 of the Combined Notes to the Consolidated Financial Statements for additional information regarding the merger.

On January 3, 2012, BGE completed implementation of its new CC&B system that is now being utilized to bill all gas and electric customers within the BGE service territory.

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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 the Registrants' 2011 Form 10-K and (b) Notes 3, 4 and 16 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

Exclusive of the *Risks Related to the Pending Merger with Constellation* described in Exelon's 2011 Form 10-K in ITEM 1A. RISK FACTORS, Exelon is, and will continue to be, subject to the risks described in Exelon's and Constellation's 2011 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 18 of the Combined Notes to Consolidated Financial Statements in Exelon's 2011 Form 10-K and Note 12 of the Notes to Consolidated Financial Statements in Constellation's 2011 Form 10-K. As a result of the merger with Constellation that closed on March 12, 2012 Exelon is subject to additional risks related to the merger as described below.

Risks Related to the Merger

The merger may not achieve its anticipated results, and Exelon may be unable to integrate the operations of Constellation in the manner expected.

Exelon and Constellation entered into the merger agreement with the expectation that the merger will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Exelon and Constellation can be integrated in an efficient, effective and timely manner.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of Exelon's businesses, processes and systems or inconsistencies in standards, controls, procedures, practices, policies and compensation arrangements, any of which could adversely affect the combined company's ability to achieve the anticipated benefits of the merger as and when expected. Exelon may have difficulty addressing possible differences in corporate cultures and management philosophies. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect Exelon's future business, financial condition, operating results and prospects.

The merger may not be accretive to earnings and may cause dilution to Exelon's earnings per share, which may negatively affect the market price of Exelon's common stock.

Exelon currently anticipates that the merger will be accretive to earnings per share in 2013, which will be the first full year following completion of the merger. This expectation is based on preliminary estimates that are subject to change. Exelon also could encounter additional transaction and integration-related costs, may fail to realize all of the benefits anticipated in the merger or be subject to other factors that affect preliminary estimates. Any of these factors could cause a decrease in Exelon's adjusted earnings per share or decrease or delay the expected accretive effect of the merger and contribute to a decrease in the price of Exelon's common stock.

The merger may adversely affect Exelon's ability to attract and retain key employees.

Current and prospective Exelon employees may experience uncertainty about their future roles at Exelon as a result of the merger. In addition, current and prospective Exelon employees and former Constellation employees may determine that they do not desire to work for the combined company for a variety of possible reasons. These factors may adversely affect Exelon's ability to attract and retain key management and other personnel.

Exelon may incur unexpected transaction fees and merger-related costs in connection with the merger.

Exelon expects to incur a number of non-recurring expenses associated with completing the merger, as well as expenses related to combining the operations of the two companies. Exelon may incur additional unanticipated costs in the integration of the businesses of Exelon and Constellation. Although Exelon expects that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction and merger-related costs over time, the combined company may not achieve this net benefit in the near term, or at all.

Exelon may encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals for the Constellation merger.

As a result of the process to obtain regulatory approvals required for the Constellation merger, Exelon is committed to various programs, contributions, investments and market mitigation measures in several settlement agreements and regulatory approval orders. It is possible that Exelon may encounter delays, unexpected difficulties or costs in meeting these commitments in compliance with the terms of the relevant agreements and orders. Failure to fulfill the commitments in accordance with their terms could result in increased costs or result in penalties or fines that could adversely affect Exelon's financial position and operating results.

Item 4. Mine Safety Disclosures

Exelon, Generation, ComEd, PECO and BGE

Not applicable to the Registrants.

Item 6. Exhibits

Exhibit No.	Description
4-1	Form of 4.25% Senior Note due 2022. (File 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.1)
4-2	Form of 5.60% Senior Note due 2042. (File 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.2)
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.

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, 2012 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 Christopher M. Crane for Exelon Generation Company, LLC
31-4	— Filed by Andrew L. Good 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, 2012 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 Christopher M. Crane for Exelon Generation Company, LLC
32-4	— Filed by Andrew L. Good 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

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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 Vice President and Corporate Controller (Principal Accounting Officer)	

August 9, 2012

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/ CHRISTOPHER M. CRANE	/s/ ANDREW L. GOOD
Christopher M. Crane President (Principal Executive Officer)	Andrew L. Good Chief Financial Officer (Principal Financial Officer)
/s/ ROBERT M. AIKEN	
Robert M. Aiken Chief Accounting Officer (Principal Accounting Officer)	

August 9, 2012

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/ KEVIN J. WADEN	
Kevin J. Waden Vice President and Controller (Principal Accounting Officer)	

August 9, 2012

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

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 9, 2012

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 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 9, 2012

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 9, 2012

Exhibit 31-2

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Jonathan W. Thayer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JONATHAN W. THAYER
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: August 9, 2012

Exhibit 31-3

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 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/ CHRISTOPHER M. CRANE
President
(Principal Executive Officer)

Date: August 9, 2012

Exhibit 31-4

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Andrew L. Good, 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/ ANDREW L. GOOD
Chief Financial Officer
(Principal Financial Officer)

Date: August 9, 2012

Exhibit 31-5

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Anne R. Pramaggiore, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ ANNE R. PRAMAGGIORE
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 9, 2012

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 9, 2012

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 9, 2012

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 9, 2012

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 9, 2012

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

Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: August 9, 2012

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, 2012, 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 9, 2012

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, 2012, 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 9, 2012

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, 2012, 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/ CHRISTOPHER M. CRANE
Christopher M. Crane
President

Date: August 9, 2012

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, 2012, 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/ ANDREW L. GOOD

Andrew L. Good
Chief Financial Officer

Date: August 9, 2012

Exhibit 32-5

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended June 30, 2012, 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 9, 2012

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, 2012, 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 9, 2012

Exhibit 32-7

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, 2012, 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 9, 2012

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, 2012, 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 9, 2012

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, 2012, 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 9, 2012

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, 2012, 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
Vice President, Chief Financial Officer and Treasurer

Date: August 9, 2012