UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the Quarterly Period Ended September 30, 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 September 30, 2012 was:

Exelon Corporation Common Stock, without par value	854,283,102
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,061,710
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
Act 129	Pennsylvania Act 129 of 2008
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AEPS	Pennsylvania Alternative Energy Portfolio Standards
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

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
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
MDE	Maryland Department of the Environment
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

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
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

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

(In millions, except per share data)	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Operating revenues	$ 6,565	$ 5,254	$17,205	$14,705
Operating expenses				
Purchased power and fuel	3,026	2,121	7,398	5,836
Operating and maintenance	2,156	1,413	5,949	3,863
Depreciation and amortization	500	332	1,376	987
Taxes other than income	290	207	737	602
Total operating expenses	5,972	4,073	15,460	11,288
Equity in earnings (losses) of unconsolidated affiliates	10	—	(69)	—
Operating income	603	1,181	1,676	3,417
Other income and (deductions)				
Interest expense	(240)	(176)	(678)	(526)
Interest expense to affiliates, net	(6)	(6)	(19)	(19)
Other, net	101	(142)	253	54
Total other income and (deductions)	(145)	(324)	(444)	(491)
Income before income taxes	458	857	1,232	2,926
Income taxes	161	255	445	1,034
Net income	297	602	787	1,892
Net income attributable to noncontrolling interests, preferred security dividends and preference stock dividends	1	1	5	3
Net income on common stock	296	601	782	1,889
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	(3)
Actuarial loss reclassified to periodic cost	44	33	126	100
Transition obligation reclassified to periodic cost	—	1	2	2
Pension and non-pension postretirement benefit plans valuation adjustment	(67)	—	(78)	39
Change in unrealized loss on cash flow hedges	(88)	(64)	(29)	(255)
Change in unrealized income on equity investments	17	—	23	—
Change in unrealized gain on foreign currency translation	2	—	—	—
Other comprehensive income (loss)	(92)	(31)	45	(117)
Comprehensive income	$ 205	$ 571	$ 832	$ 1,775
Average shares of common stock outstanding:				
Basic	854	663	804	663
Diluted	857	665	806	664
Earnings per average common share:				
Basic	$ 0.35	$ 0.91	$ 0.97	$ 2.85
Diluted	$ 0.35	$ 0.90	$ 0.97	$ 2.84
Dividends per common share	$ 0.53	$ 0.53	$ 1.58	$ 1.58

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2012	2011
Cash flows from operating activities		
Net income	$ 787	$ 1,892
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	2,909	1,702
Impairment of assets held for sale	278	—
Deferred income taxes and amortization of investment tax credits	263	1,008
Net fair value changes related to derivatives	(377)	360
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(142)	90
Other non-cash operating activities	1,235	703
Changes in assets and liabilities:		
Accounts receivable	240	3
Inventories	12	(44)
Accounts payable, accrued expenses and other current liabilities	(837)	(400)
Option premiums (paid) received, net	(122)	59
Counterparty collateral received (posted), net	408	(807)
Income taxes	465	532
Pension and non-pension postretirement benefit contributions	(131)	(2,089)
Other assets and liabilities	(431)	(92)
Net cash flows provided by operating activities	4,557	2,917
Cash flows from investing activities		
Capital expenditures	(4,145)	(2,972)
Proceeds from nuclear decommissioning trust fund sales	6,262	3,120
Investment in nuclear decommissioning trust funds	(6,422)	(3,293)
Acquisitions	—	(380)
Cash acquired from Constellation	964	—
Proceeds from sales of investments	26	—
Purchases of investments	(13)	—
Change in restricted cash	(38)	(532)
Other investing activities	41	26
Net cash flows used in investing activities	(3,325)	(4,031)
Cash flows from financing activities		
Changes in short-term debt	(139)	462
Issuance of long-term debt	1,558	1,199
Retirement of long-term debt	(731)	(3)
Dividends paid on common stock	(1,226)	(1,044)
Dividends paid to former Constellation shareholders	(51)	—
Proceeds from employee stock plans	61	26
Other financing activities	(20)	(67)
Net cash flows (used in) provided by financing activities	(548)	573
Increase (decrease) in cash and cash equivalents	684	(541)
Cash and cash equivalents at beginning of period	1,016	1,612
Cash and cash equivalents at end of period	$ 1,700	$ 1,071

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2012 (Unaudited)	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,602	$ 1,016
Cash and cash equivalents of variable interest entities	98	—
Restricted cash and investments	73	40
Restricted cash and investments of variable interest entities	67	—
Accounts receivable, net		
Customer ($314 and $329 gross accounts receivable pledged as collateral as of September 30, 2012 and December 31, 2011, respectively)	2,835	1,613
Other	1,216	1,000
Accounts receivable, net, variable interest entities	225	—
Mark-to-market derivative assets	928	432
Unamortized energy contract assets	1,141	13
Inventories, net		
Fossil fuel	264	208
Materials and supplies	767	656
Deferred income taxes	254	—
Regulatory assets	786	390
Other	1,072	345
Total current assets	11,328	5,713
Property, plant and equipment, net	43,914	32,570
Deferred debits and other assets		
Regulatory assets	6,192	4,518
Nuclear decommissioning trust funds	7,140	6,507
Investments	838	751
Investments in affiliates	371	15
Investment in CENG	1,908	—
Goodwill	2,625	2,625
Mark-to-market derivative assets	1,039	650
Unamortized energy contracts assets	1,191	388
Pledged assets for Zion Station decommissioning	631	734
Other	1,176	524
Total deferred debits and other assets	23,111	16,712
Total assets	$ 78,353	$ 54,995

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2012 (Unaudited)	December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 60	$ 163
Short-term notes payable — accounts receivable agreement	225	225
Long-term debt due within one year	1,049	828
Long-term debt of variable interest entities due within one year	70	—
Accounts payable	2,359	1,444
Accounts payable of variable interest entities	132	—
Accrued expenses	1,502	1,255
Deferred income taxes	52	1
Regulatory liabilities	299	197
Dividends payable	4	349
Mark-to-market derivative liabilities	521	112
Unamortized energy contract liabilities	523	—
Other	974	560
Total current liabilities	7,770	5,134
Long-term debt	17,050	11,799
Long-term debt to financing trusts	649	390
Long-term debt of variable interest entity	546	—
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	11,600	8,253
Asset retirement obligations	4,866	3,884
Pension obligations	2,575	2,194
Non-pension postretirement benefit obligations	2,946	2,263
Spent nuclear fuel obligation	1,020	1,019
Regulatory liabilities	4,000	3,627
Mark-to-market derivative liabilities	407	126
Unamortized energy contract liabilities	621	—
Payable for Zion Station decommissioning	422	563
Other	1,691	1,268
Total deferred credits and other liabilities	30,148	23,197
Total liabilities	56,163	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 September 30, 2012 and December 31, 2011, respectively)	16,594	9,107
Treasury stock, at cost (35 shares at September 30, 2012 and December 31, 2011, respectively)	(2,327)	(2,327)
Retained earnings	9,959	10,055
Accumulated other comprehensive loss, net	(2,405)	(2,450)
Total shareholders' equity	21,821	14,385
BGE preference stock not subject to mandatory redemption	193	—
Noncontrolling interest	89	3
Total equity	22,103	14,388
Total liabilities and shareholders' equity	$ 78,353	$ 54,995

See the Combined Notes to Consolidated Financial Statements

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

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Non-controlling Interest	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	—	—	—	782	—	(6)	11	787
Long-term incentive plan activity	2,790	122	—	—	—	—	—	122
Common stock dividends	—	—	—	(878)	—	—	—	(878)
Common stock issuance —Constellation merger	188,124	7,365	—	—	—	—	—	7,365
Noncontrolling interest acquired	—	—	—	—	—	92	—	92
BGE preference stock acquired	—	—	—	—	—	—	193	193
Preferred and preference stock dividends	—	—	—	—	—	—	(11)	(11)
Other comprehensive income net of income taxes of $(87)	—	—	—	—	45	—	—	45
Balance, September 30, 2012	889,026	$16,594	$(2,327)	$ 9,959	$ (2,405)	$ 89	$ 193	$22,103

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Operating revenues				
Operating revenues	$ 3,558	$ 2,517	$ 9,276	$ 7,063
Operating revenues from affiliates	459	304	1,233	856
Total operating revenues	4,017	2,821	10,509	7,919
Operating expenses				
Purchased power and fuel	2,122	1,071	5,018	2,795
Operating and maintenance	1,289	713	3,319	2,084
Operating and maintenance from affiliates	126	77	437	222
Depreciation and amortization	207	139	564	416
Taxes other than income	109	67	272	199
Total operating expenses	3,853	2,067	9,610	5,716
Equity in earnings (losses) of unconsolidated affiliates	10	—	(69)	—
Operating income	174	754	830	2,203
Other income and (deductions)				
Interest expense	(85)	(37)	(223)	(128)
Other, net	83	(164)	185	(12)
Total other income and (deductions)	(2)	(201)	(38)	(140)
Income before income taxes	172	553	792	2,063
Income taxes	85	167	373	738
Net income	87	386	419	1,325
Net loss attributable to noncontrolling interests	(4)	—	(6)	—
Net income on membership interest	91	386	425	1,325
Other comprehensive income (loss), net of income taxes				
Change in unrealized loss on cash flow hedges	(171)	(125)	(185)	(448)
Change in unrealized income on equity investments	17	—	23	—
Change in unrealized income on foreign currency translation	2	—	—	—
Change in unrealized loss on marketable securities	—	—	(1)	—
Other comprehensive loss	(152)	(125)	(163)	(448)
Comprehensive income (loss)	$ (65)	$ 261	$ 256	$ 877

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2012	2011
Cash flows from operating activities		
Net income	$ 419	$ 1,325
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	2,178	1,131
Impairment on assets held for sale	278	—
Deferred income taxes and amortization of investment tax credits	69	336
Net fair value changes related to derivatives	(345)	360
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(142)	90
Other non-cash operating activities	422	362
Changes in assets and liabilities:		
Accounts receivable	189	(165)
Receivables from and payables to affiliates, net	(58)	210
Inventories	34	(32)
Accounts payable, accrued expenses and other current liabilities	(546)	(1)
Option premiums (paid) received, net	(122)	59
Counterparty collateral received (paid), net	315	(804)
Income taxes	565	268
Pension and non-pension postretirement benefit contributions	(48)	(952)
Other assets and liabilities	(195)	(65)
Net cash flows provided by operating activities	3,013	2,122
Cash flows from investing activities		
Capital expenditures	(2,602)	(1,865)
Proceeds from nuclear decommissioning trust fund sales	6,262	3,120
Investment in nuclear decommissioning trust funds	(6,422)	(3,293)
Acquisitions	—	(380)
Cash acquired from Constellation	708	—
Other investing activities	(2)	(3)
Net cash flows used in investing activities	(2,056)	(2,421)
Cash flows from financing activities		
Issuance of long-term debt	957	—
Retirement of long-term debt	(138)	(2)
Change in short-term debt	(41)	72
Distribution to member	(1,384)	(61)
Contribution from member	—	30
Other financing activities	(17)	(53)
Net cash flows used in financing activities	(623)	(14)
Increase (decrease) in cash and cash equivalents	334	(313)
Cash and cash equivalents at beginning of period	496	456
Cash and cash equivalents at end of period	$ 830	$ 143

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2012 (Unaudited)	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 732	$ 496
Cash and cash equivalents of variable interest entities	98	—
Restricted cash and cash equivalents	1	5
Restricted cash and cash equivalents of variable interest entities	19	—
Accounts receivable, net		
Customer	1,580	578
Other	291	257
Accounts receivable, net, variable interest entities	225	—
Mark-to-market derivative assets	928	432
Mark-to-market derivative assets with affiliates	352	503
Receivables from affiliates	130	109
Unamortized energy contract assets	1,141	13
Inventories, net		
Fossil fuel	136	120
Materials and supplies	620	556
Other	905	148
Total current assets	7,158	3,217
Property, plant and equipment, net	18,708	13,475
Deferred debits and other assets		
Nuclear decommissioning trust funds	7,140	6,507
Investments	82	41
Investments in affiliates	348	1
Investment in CENG	1,908	—
Mark-to-market derivative assets	1,026	635
Mark-to-market derivative assets with affiliates	—	191
Prepaid pension asset	2,021	2,068
Pledged assets for Zion Station decommissioning	631	734
Unamortized energy contract assets	1,191	388
Other	877	176
Total deferred debits and other assets	15,224	10,741
Total assets	$ 41,090	$ 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)	September 30, 2012 (Unaudited)	December 31, 2011
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 11	$ 2
Long-term debt due within one year	23	3
Long-term debt due within one year of variable interest entities	4	—
Accounts payable	1,501	753
Accounts payable of variable interest entities	132	—
Accrued expenses	1,106	779
Payables to affiliates	99	58
Deferred income taxes	69	244
Mark-to-market derivative liabilities	504	103
Unamortized energy contract liabilities	429	—
Other	377	202
Total current liabilities	4,255	2,144
Long-term debt	7,148	3,674
Long-term debt of variable interest entities	208	—
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,410	3,966
Asset retirement obligations	4,730	3,767
Non-pension postretirement benefit obligations	849	703
Spent nuclear fuel obligation	1,020	1,019
Payables to affiliates	2,383	2,222
Mark-to-market derivative liabilities	355	29
Unamortized energy contract liabilities	589	—
Payable for Zion Station decommissioning	422	563
Other	791	638
Total deferred credits and other liabilities	16,549	12,907
Total liabilities	28,160	18,725
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	8,814	3,556
Undistributed earnings	3,273	4,232
Accumulated other comprehensive income, net	752	915
Total member's equity	12,839	8,703
Noncontrolling interest	91	5
Total equity	12,930	8,708
Total liabilities and equity	$ 41,090	$ 27,433

See the Combined Notes to Consolidated Financial Statements

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

	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Income, net	Noncontrolling Interest	Total Equity
Balance, December 31, 2011	$ 3,556	$ 4,232	$ 915	$ 5	$ 8,708
Net income	—	425	—	(6)	419
Acquisition of Constellation	5,258	—	—	—	5,258
Noncontrolling interest acquired	—	—	—	92	92
Distribution to member	—	(1,384)	—	—	(1,384)
Other comprehensive loss, net of income taxes of $107	—	—	(163)	—	(163)
Balance, September 30, 2012	$ 8,814	$ 3,273	$ 752	$ 91	$12,930

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Operating revenues				
Operating revenues	$ 1,484	$ 1,783	$ 4,152	$ 4,692
Operating revenues from affiliates	—	1	2	2
Total operating revenues	1,484	1,784	4,154	4,694
Operating expenses				
Purchased power	498	773	1,255	1,986
Purchased power from affiliate	180	159	631	450
Operating and maintenance	313	356	882	817
Operating and maintenance from affiliate	37	40	118	113
Depreciation and amortization	157	135	458	405
Taxes other than income	81	78	224	226
Total operating expenses	1,266	1,541	3,568	3,997
Operating income	218	243	586	697
Other income and (deductions)				
Interest expense	(71)	(82)	(221)	(246)
Interest expense to affiliates, net	(3)	(4)	(9)	(11)
Other, net	5	16	12	24
Total other income and (deductions)	(69)	(70)	(218)	(233)
Income before income taxes	149	173	368	464
Income taxes	59	61	149	169
Net income	90	112	219	295
Other comprehensive income, net of income taxes				
Change in unrealized gain on marketable securities	—	—	1	—
Other comprehensive income	—	—	1	—
Comprehensive income	$ 90	$ 112	$ 220	$ 295

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Cash flows from operating activities		
Net income	$ 219	$ 295
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	458	405
Deferred income taxes and amortization of investment tax credits	198	527
Other non-cash operating activities	310	210
Changes in assets and liabilities:		
Accounts receivable	22	(4)
Receivables from and payables to affiliates, net	(32)	(13)
Inventories	(11)	(11)
Accounts payable, accrued expenses and other current liabilities	(49)	(160)
Counterparty collateral received (paid), net	93	(3)
Income taxes	116	211
Pension and non-pension postretirement benefit contributions	(19)	(871)
Other assets and liabilities	(124)	29
Net cash flows provided by operating activities	1,181	615
Cash flows from investing activities		
Capital expenditures	(896)	(758)
Proceeds from sales of investments	26	4
Purchases of investments	(13)	(2)
Change in restricted cash	—	(536)
Other investing activities	12	16
Net cash flows used in investing activities	(871)	(1,276)
Cash flows from financing activities		
Changes in short-term debt	35	—
Issuance of long-term debt	—	1,199
Retirement of long-term debt	(450)	(1)
Dividends paid on common stock	(95)	(225)
Other financing activities	(3)	(6)
Net cash flows (used in) provided by financing activities	(513)	967
(Decrease) Increase in cash and cash equivalents	(203)	306
Cash and cash equivalents at beginning of period	234	50
Cash and cash equivalents at end of period	$ 31	$ 356

See the Combined Notes to Consolidated Financial Statements

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2012 (Unaudited)	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 31	$ 234
Restricted cash	—	3
Accounts receivable, net		
Customer	602	655
Other	274	385
Inventories, net	92	81
Deferred income taxes	87	61
Counterparty collateral deposited	—	90
Regulatory assets	511	657
Other	27	22
Total current assets	1,624	2,188
Property, plant and equipment, net	13,611	13,121
Deferred debits and other assets		
Regulatory assets	589	699
Investments	9	21
Investments in affiliates	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,024	1,860
Prepaid pension asset	1,698	1,803
Other	285	315
Total deferred debits and other assets	7,236	7,329
Total assets	$ 22,471	$ 22,638

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)	September 30, 2012 (Unaudited)	December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 35	$ —
Long-term debt due within one year	252	450
Accounts payable	326	325
Accrued expenses	220	318
Payables to affiliates	84	111
Customer deposits	137	136
Regulatory liabilities	172	137
Mark-to-market derivative liability	17	9
Mark-to-market derivative liability with affiliate	352	503
Other	128	82
Total current liabilities	1,723	2,071
Long-term debt	4,965	5,215
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,201	3,993
Asset retirement obligations	99	89
Non-pension postretirement benefits obligations	359	271
Regulatory liabilities	3,206	3,042
Mark-to-market derivative liability	53	97
Mark-to-market derivative liability with affiliate	—	191
Other	484	426
Total deferred credits and other liabilities	8,402	8,109
Total liabilities	15,296	15,601
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	5,016	5,003
Retained earnings	571	447
Accumulated other comprehensive loss, net	—	(1)
Total shareholders' equity	7,175	7,037
Total liabilities and shareholders' equity	$ 22,471	$ 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	—	—	219	—	—	219
Appropriation of retained earnings for future dividends	—	—	(219)	219	—	—
Common stock dividends	—	—	—	(95)	—	(95)
Allocation of tax benefit from parent	—	13	—	—	—	13
Other comprehensive income, net of income taxes of $0	—	—	—	—	1	1
Balance, September 30, 2012	$ 1,588	$ 5,016	$ (1,639)	$ 2,210	$ —	$ 7,175

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 September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Operating revenues				
Operating revenues	$ 805	$ 944	$ 2,393	$ 2,938
Operating revenues from affiliates	1	2	3	4
Total operating revenues	806	946	2,396	2,942
Operating expenses				
Purchased power and fuel	155	327	626	1,112
Purchased power from affiliate	171	137	407	394
Operating and maintenance	172	195	491	529
Operating and maintenance from affiliates	27	24	83	68
Depreciation and amortization	55	51	161	150
Taxes other than income	48	59	122	165
Total operating expenses	628	793	1,890	2,418
Operating income	178	153	506	524
Other income and (deductions)				
Interest expense	(29)	(31)	(85)	(93)
Interest expense to affiliates, net	(3)	(3)	(9)	(9)
Other, net	2	3	6	11
Total other income and (deductions)	(30)	(31)	(88)	(91)
Income before income taxes	148	122	418	433
Income taxes	25	17	118	119
Net income	123	105	300	314
Preferred security dividends	1	1	3	3
Net income on common stock	122	104	297	311
Comprehensive income, net of income taxes				
Net income	123	105	300	314
Other comprehensive income, net of income taxes				
Change in unrealized gains on marketable securities	—	—	1	—
Other comprehensive income	—	—	1	—
Comprehensive income	$ 123	$ 105	$ 301	$ 314

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

(In millions)	Nine Months Ended September 30, 2012	2011
Cash flows from operating activities		
Net income	$ 300	$ 314
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	161	150
Deferred income taxes and amortization of investment tax credits	27	181
Other non-cash operating activities	96	74
Changes in assets and liabilities:		
Accounts receivable	36	241
Receivables from and payables to affiliates, net	15	(217)
Inventories	10	—
Accounts payable, accrued expenses and other current liabilities	(75)	24
Income taxes	127	27
Pension and non-pension postretirement benefit contributions	(12)	(110)
Other assets and liabilities	(57)	(28)
Net cash flows provided by operating activities	628	656
Cash flows from investing activities		
Capital expenditures	(274)	(321)
Changes in Exelon intercompany money pool	5	(91)
Change in restricted cash	2	(2)
Other investing activities	8	12
Net cash flows used in investing activities	(259)	(402)
Cash flows from financing activities		
Issuance of long-term debt	350	—
Dividends paid on common stock	(258)	(268)
Dividends paid on preferred securities	(3)	(3)
Contributions from parent	—	18
Other financing activities	(4)	(5)
Net cash flows provided by (used in) financing activities	85	(258)
Increase (decrease) in cash and cash equivalents	454	(4)
Cash and cash equivalents at beginning of period	194	522
Cash and cash equivalents at end of period	$ 648	$ 518

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2012 (Unaudited)	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 648	$ 194
Restricted cash and cash equivalents	—	2
Accounts receivable, net ($314 and $329 gross accounts receivable pledged as collateral as of September 30, 2012 and December 31, 2011, respectively)		
Customer	294	380
Other	240	376
Inventories, net		
Fossil fuel	75	87
Materials and supplies	20	18
Deferred income taxes	39	25
Receivable from Exelon intercompany money pool	77	82
Prepaid utility taxes	57	1
Regulatory assets	42	39
Other	38	39
Total current assets	1,530	1,243
Property, plant and equipment, net	5,996	5,874
Deferred debits and other assets		
Regulatory assets	1,323	1,216
Investments	23	22
Investments in affiliates	8	8
Receivable from affiliates	362	365
Prepaid pension asset	378	382
Other	41	46
Total deferred debits and other assets	2,135	2,039
Total assets	$ 9,661	$ 9,156

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	September 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	200	262
Accrued expenses	87	83
Payables to affiliates	76	62
Customer deposits	51	53
Regulatory liabilities	105	60
Other	26	25
Total current liabilities	1,145	1,145
Long-term debt	1,947	1,597
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,281	2,170
Asset retirement obligations	29	28
Non-pension postretirement benefits obligations	310	288
Regulatory liabilities	582	585
Other	118	134
Total deferred credits and other liabilities	3,320	3,205
Total liabilities	6,596	6,131
Commitments and contingencies		
Preferred securities	87	87
Shareholders' equity		
Common stock	2,379	2,379
Retained earnings	598	559
Accumulated other comprehensive income, net	1	—
Total shareholders' equity	2,978	2,938
Total liabilities and shareholders' equity	$ 9,661	$ 9,156

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	Total Shareholders' Equity
Balance, December 31, 2011	$ 2,379	$ 559	$ —	$ 2,938
Net income	—	300	—	300
Common stock dividends	—	(258)	—	(258)
Preferred security dividends	—	(3)	—	(3)
Other comprehensive income, net of income taxes of $0	—	—	1	1
Balance, September 30, 2012	$ 2,379	$ 598	$ 1	$ 2,978

See the Combined Notes to Consolidated Financial Statements

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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 September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Operating revenues				
Operating revenues	$ 716	$ 742	$ 2,023	$ 2,388
Operating revenues from affiliates	4	3	9	6
Total operating revenues	720	745	2,032	2,394
Operating expenses				
Purchased power and fuel	253	268	747	1,021
Purchased power from affiliate	120	137	296	267
Operating and maintenance	172	184	460	433
Operating and maintenance from affiliates	29	26	97	96
Depreciation and amortization	68	60	218	205
Taxes other than income	48	47	143	143
Total operating expenses	690	722	1,961	2,165
Operating income	30	23	71	229
Other income and (deductions)				
Interest expense	(35)	(32)	(110)	(97)
Other, net	5	8	18	22
Total other income and (deductions)	(30)	(24)	(92)	(75)
Income (loss) before income taxes	—	(1)	(21)	154
Income taxes	—	(3)	(7)	55
Net income (loss)	—	2	(14)	99
Preference stock dividends	4	4	10	10
Net income (loss) on common stock	$ (4)	$ (2)	$ (24)	$ 89
Comprehensive income (loss)	$ —	$ 2	$ (14)	$ 99

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

(In millions)	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Cash flows from operating activities		
Net (loss) income	$ (14)	$ 99
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	218	205
Deferred income taxes and amortization of investment tax credits	101	93
Other non-cash operating activities	147	98
Changes in assets and liabilities:		
Accounts receivable	11	90
Receivables from and payables to affiliates, net	4	(5)
Inventories	21	(20)
Accounts payable, accrued expenses and other current liabilities	(16)	(18)
Income taxes	(50)	56
Pension and non-pension postretirement benefit contributions	(13)	(17)
Other assets and liabilities	(86)	(154)
Net cash flows provided by operating activities	323	427
Cash flows from investing activities		
Capital expenditures	(402)	(416)
Change in restricted cash	(19)	(22)
Other investing activities	8	—
Net cash flows used in investing activities	(413)	(438)
Cash flows from financing activities		
Changes in short-term debt	—	140
Issuance of long-term debt	250	—
Repayment of long-term debt	(141)	(30)
Dividends paid on common stock	—	(85)
Dividends paid on preference stock	(10)	(10)
Contributions from parent	66	—
Other financing activities	(3)	(3)
Net cash flows provided by financing activities	162	12
Increase in cash and cash equivalents	72	1
Cash and cash equivalents at beginning of period	49	50
Cash and cash equivalents at end of period	$ 121	$ 51

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2012 (Unaudited)	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 121	$ 49
Restricted cash and cash equivalents of variable interest entity	49	30
Accounts receivable, net		
Customer	358	428
Other	120	90
Income taxes receivable	61	21
Inventories, net		
Gas held in storage	53	74
Materials and supplies	34	34
Prepaid utility taxes	85	56
Regulatory assets	189	174
Other	8	12
Total current assets	1,078	968
Property, plant and equipment, net	5,378	5,132
Deferred debits and other assets		
Regulatory assets	534	550
Investments	5	—
Investments in affiliates	8	8
Prepaid pension asset	477	514
Other	24	29
Total deferred debits and other assets	1,048	1,101
Total assets	$ 7,504	$ 7,201

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2012 (Unaudited)	December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long-term debt due within one year	$ 400	$ 110
Long-term debt of variable interest entity due within one year	65	63
Accounts payable	190	210
Accrued expenses	125	148
Deferred income taxes	56	59
Payables to affiliates	44	41
Customer deposits	75	84
Regulatory liabilities	22	18
Other	71	25
Total current liabilities	1,048	758
Long-term debt	1,446	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	1,598	1,491
Asset retirement obligations	8	1
Non-pension postretirement benefits obligations	208	212
Regulatory liabilities	212	200
Other	84	52
Total deferred credits and other liabilities	2,110	1,956
Total liabilities	5,161	4,900
Commitments and contingencies		
Shareholders' equity		
Common stock	1,360	1,294
Retained earnings	793	817
Total shareholders' equity	2,153	2,111
Preference stock not subject to mandatory redemption	190	190
Total equity	2,343	2,301
Total liabilities and shareholders' equity	$ 7,504	$ 7,201

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	—	(10)	(10)	—	(10)
Contribution from parent	66	—	66	—	66
Balance, September 30, 2012	$ 1,360	$ 793	$ 2,153	$ 190	$2,343

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 reporting requirements as an SEC registrant. The information disclosed for BGE represents the activity of the standalone entity for the three and nine months ended September 30, 2012 and 2011 and the financial position as of September 30, 2012 and December 31, 2011. However, for Exelon's financial reporting, Exelon is reporting BGE activity from March 12, 2012 through September 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 September 30, 2012 and 2011 and for the three and nine months then ended are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants' respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The

December 31, 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 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, the largest of which is a 230-MW solar project under development in northern Los Angeles County, California. As of September 30, 2012, this project consisted primarily of Current Assets of $69 million, Noncurrent Assets of approximately $516 million, Current Liabilities of $230 million, and Noncurrent Liabilities of $159 million. See Note 3 — Other Acquisitions and Note 9 — Debt and Credit Agreements for additional information; 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 nine months ended September 30, 2012, BGE remitted $27 million and $62 million, respectively, to BondCo. During the three and nine months ended September 30, 2011, BGE remitted $27 million and $65 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 nine months ended September 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, Generation's or BGE's general credit.

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

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

	September 30, 2012		
	Exelon	Generation	BGE
Current assets	$ 398	$ 348	$ 49
Noncurrent assets	471	432	—
Total assets	$ 869	$ 780	$ 49
Current liabilities	$ 269	$ 193	$ 75
Noncurrent liabilities	573	235	299
Total liabilities	$ 842	$ 428	$374

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 September 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:

September 30, 2012	Energy Contract VIEs	Equity Method Investment VIEs	Total
Total assets(a)	$ 280	$ 342	$622
Total liabilities(a)	217	95	312
Registrants' ownership interest(a)	—	98	98
Other ownership interests(a)	63	149	212
Registrants' maximum exposure to loss:			
Letters of credit	8	—	8
Carrying amount of equity method investments	—	78	78
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 nine months ended September 30, 2012, ComEd, PECO, BGE and Generation assessed their contracts and determined that, other than the items discussed in this note 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 September 30, 2012. The guidance is effective for the Registrants beginning with the period ended March 31, 2012 and is required to be applied prospectively. However, the Company updated the existing fair value disclosures during the first quarter of 2012 to comply with the requirements for this standard. See Note 7 — Fair Value of Financial Assets and Liabilities for the new disclosures.

3. Merger and Acquisitions

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

Description of Transaction

On March 12, 2012, Exelon completed the merger contemplated by the Merger Agreement, among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation's interest in RF HoldCo LLC, which holds Constellation's interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon's interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including 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 nine months ended September 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. Such costs, which are expected to be primarily capital in nature, will be recognized as incurred. As of September 30, 2012, amounts reflected in the Exelon and Generation consolidated financial statements for these expenditure commitments were immaterial.

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 the 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.

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 DOJ approved the buyer on October 18, 2012 and the final FERC approval was obtained on October 19, 2012; the transaction 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 estimated net proceeds from the sale of approximately $356 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 Generation's estimated fair value of the Maryland generating stations. Consequently, Exelon and Generation recorded a pre-tax loss of $278 million in operating and maintenance expense in the third quarter of 2012 to reflect the difference between the estimated sales price and carrying value. The final loss amount will be updated for adjustments related to fuel inventory, capital expenditures, and timing of the closing.

As of September 30, 2012, these assets, classified as held for sale, are valued at estimated fair value less costs to sell of $339 million, after reflecting the $278 million impairment, and are included in the other current assets balance on Exelon's and Generation's Consolidated Balance Sheets.

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 has coordinated with PJM to determine the impact on Generation's revenues and the market from this error and these adjustments, and Generation has worked with PJM to reverse the financial impacts. Generation is in discussions with the DOJ regarding resolution of this matter. The final resolution is not expected to have a material impact on Exelon's or Generation's results of operations, cash flows or financial position.

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. The preliminary valuations performed in the first quarter of 2012 were updated in the second and third quarters of 2012, with the most significant adjustments to the preliminary valuation amounts having been made to the fair values assigned to the acquired power supply 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 September 30, 2012 was as follows:

Preliminary Purchase Price Allocation, excluding amortization	Exelon	Generation
Current assets	$ 4,936	$ 3,638
Property, plant and equipment	9,240	3,948
Unamortized energy contracts	3,218	3,218
Other intangibles, trade name and retail relationships	457	457
Investment in affiliates	1,942	1,942
Pension and OPEB regulatory asset	740	—
Other assets	2,668	1,266
Total assets	23,201	14,469
Current liabilities	3,431	2,798
Unamortized energy contracts	1,722	1,512
Long-term debt, including current maturities	6,038	2,972
Noncontrolling interest	92	92
Deferred credits and other liabilities and preferred securities	4,553	1,837
Total liabilities, preferred securities and noncontrolling interest	15,836	9,211
Total purchase price	$ 7,365	$ 5,258

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 their Consolidated Balance Sheets the unamortized energy contract assets and liabilities for these contracts. Exelon amortization expense for the three months ended September 30, 2012 and for the period March 12, 2012 to September 30, 2012 were $224 million and $714 million, respectively. 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 determined to be 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 determined to be 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 12.4 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 September 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	$1,496	$ (714)	$ 782	$ 267	$396	$ 76	$18	$(31)
Trade name	10.0	243	(14)	229	10	24	24	24	24
Retail relationships	12.4	214	(9)	205	8	19	19	19	19
Total, net		$1,953	$ (737)	$1,216	$ 285	$439	$119	$61	$ 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(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 $720 million and net income of $0 million during three months ended September 30, 2012, and operating revenues of $ 1,388 million and net loss of $49 million during the nine months ended September 30, 2012.

During the three months ended September 30, 2012, Exelon, Generation, PECO and BGE incurred merger and integration-related costs of $87 million, $79 million, $3 million and $1 million, respectively. During the nine months ended September 30, 2012, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $671 million, $283 million, $2 million, $13 million and $155 million, respectively. These amounts do not include merger and integration-related costs of $34 million and $22 million incurred at ComEd and BGE, respectively, that have been recorded as a regulatory asset. The costs incurred are classified primarily within Operating and Maintenance Expense in the Registrants' respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the BGE customer rate credit and the credit facility fees, which are included as a reduction to operating revenues and other, net, respectively, for the nine months ended September 30, 2012.

During the three months ended September 30, 2011, Exelon, Generation, ComEd and PECO incurred merger and integration-related costs of $18 million, $5 million, $2 million and $1 million, respectively. During the nine months ended September 30, 2011, Exelon, Generation, ComEd and PECO incurred merger and integration-related costs of $43 million, $6 million, $2 million and $1 million, respectively. These costs are classified primarily within Operating and Maintenance Expense in the Registrants' respective Consolidated Statements of Operations and Comprehensive Income.

Severance Costs

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

Upon closing the merger with Constellation, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. The majority of these positions are corporate and Generation support positions. Since then, Exelon has identified specific employees to be severed pursuant to the merger-related staffing and selection process; as well as employees that were previously identified for severance but have since accepted another position within Exelon and are no longer receiving a severance benefit. Exelon adjusts its accrual each quarter to reflect its best estimate of remaining severance costs. The amount of severance expense associated with the post-merger integration recognized through September 30, 2012, for Exelon is $130 million, which includes $76 million, $18 million, $8 million and $19 million for Generation, ComEd, PECO and BGE, respectively. Estimated costs to be incurred after September 30, 2012 are not material. 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.

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

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

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

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

(a) The amounts above include $0 million and $40 million at Generation, $2 million and $16 million at ComEd, $1 million and $8 million at PECO, and $1 million and $7 million at BGE, for amounts billed by BSC through intercompany allocations for the three and nine months ended September 30, 2012, respectively.

(b) ComEd established regulatory assets of $18 million, as of September 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 $19 million, as of September 30, 2012, for severance benefits costs. The majority of these costs are expected to be recovered over a five-year period.

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 September 30, 2012 Severance liability	Exelon	Generation	ComEd	PECO	BGE
Balance at June 30, 2012	$ 118	$ 30	$ 2	$ —	$ 12
Severance charges(a)	7	4	—	—	—
Stock compensation	3	1	—	—	—
One-time termination benefits(b)	1	1	—	—	—
Other charges(c)	—	—	—	—	—
Payments	(9)	(2)	—	—	(1)
Balance at September 30, 2012	$ 120	$ 34	$ 2	$ —	$ 11

Nine Months Ended September 30, 2012 Severance liability	Exelon	Generation	ComEd	PECO	BGE
Balance at December 31, 2011	$ —	$ —	$ —	$ —	$—
Severance charges(a)	114	31	2	—	11
Stock compensation	6	2	—	—	—
One-time termination benefits(b)	3	1	—	—	—
Other charges(c)	7	2	—	—	1
Payments	(10)	(2)	—	—	(1)
Balance at September 30, 2012	$ 120	$ 34	$ 2	$ —	$ 11

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

(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.

Pro-forma Impact of the Merger

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

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

	Generation Three Months Ended September 30,		Exelon Three Months Ended September 30,	
	2012	2011(a)	2012	2011(b)
Total Revenues	$ 4,293	$ 5,133	$ 6,841	$ 8,219
Net income attributable to Exelon	282	163	492	379
Basic Earnings Per Share	n.a.	n.a.	$ 0.58	$ 0.45
Diluted Earnings Per Share	n.a.	n.a.	0.57	0.44

	Generation Nine Months Ended September 30,		Exelon Nine Months Ended September 30,	
	2012	2011(a)	2012	2011(b)
Total Revenues	$12,753	$14,996	$20,084	$23,839
Net income attributable to Exelon	805	690	1,439	1,119
Basic Earnings Per Share	n.a.	n.a.	$ 1.79	$ 1.32
Diluted Earnings Per Share	n.a.	n.a.	1.79	1.31

(a) The amounts above include non-recurring costs directly related to the merger of $69 million and $318 million for the three and nine months ended September 30, 2011, respectively.
(b) The amounts above include non-recurring costs directly related to the merger of $74 million and $242 million for the three and nine months ended September 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.

Other Development. As part of its plan to construct multiple wind facilities in 2012, Generation has acquired several project entities. In addition, Generation has acquired solar projects and interests in oil and gas production facilities in 2012. 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.

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 29, 2012, the ICC issued its final Order (May Order) in that proceeding. The May 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 a subsequent 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 May Order.

On June 22, 2012, the ICC granted an expedited rehearing on the issues of 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. On October 3, 2012, the ICC issued its final order (Rehearing Order) in ComEd's expedited rehearing. The Rehearing Order adopted ComEd's position on the return on its pension asset, resulting in an increase in ComEd's annual revenue requirement. In two other areas, the ICC ruled against ComEd by reaffirming use of an average rather than year-end rate base in ComEd's reconciliation revenue requirement; and amending its prior order to provide a short-term debt rate as the appropriate interest rate to apply to under/over recoveries of incurred costs. ComEd filed an appeal of the May Order and the Rehearing Order in court on October 4, 2012. ComEd expects to record in the fourth quarter of 2012 an increase in revenue of approximately $135 million pre-tax consistent with the terms of the Rehearing Order.

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 filing with the ICC 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. However, as a result of the Rehearing Order above, ComEd is delaying certain elements of the AMI Deployment Plan, including the delay of installation of additional smart meters. ComEd has outlined the new deployment schedule within testimony provided in the AMI Plan Rehearing on October 3, 2012. As a result of the Rehearing Order ComEd has deferred approximately $50 million of the 2012 AMI Deployment Plan and $15 million of planned capital investment to future years. An Order from the ICC on ComEd's revised deployment plan is due by December 5, 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 May 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 September 30, 2012 and December 31, 2011, ComEd recorded an estimated net regulatory asset of $74 million and $84 million, respectively, which represents the ICC's approved distribution formula and associated rulings as of September 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 nine months ended September 30, 2012. The evidentiary hearing in ComEd's 2011 reconciliation rate case was held on September 25, 2012, and a final order is 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, as discussed above.

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 the ICC's approval of 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. The Illinois Supreme Court denied the Petition on September 26, 2012, and returned the matter to the ICC to calculate a refund amount. 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. In September 2012, PECO completed its last competitive procurement under the DSP Program for electric supply for default electric service. PECO entered into block contracts with PAPUC-approved bidders, including Generation, 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.

On October 12, 2012, the PAPUC issued its Opinion and Order approving PECO's second DSP Plan, which was filed with the PAPUC in January 2012. The plan, which has a 24-month term from June 1, 2013 through May 31, 2015, complies with electric generation procurement guidelines set forth in Act 129. Under the second 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, administrative costs and AEPS 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 24-month term.

In the second DSP plan, the load for the residential and small and medium commercial classes will be served through competitively procured contracts for fixed price, full requirements contracts of two years or less. Similar to the current DSP plan, for the large commercial and industrial class load, PECO will competitively procure contracts for full requirements default electric generation with the price for energy in each contract set to be the hourly price of the spot market during the term of delivery. The first competitive procurement is expected to take place for the residential class in December 2012 for default electric service commencing June 1, 2013.

In addition, the second DSP plan includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. In the PAPUC's Opinion and Order, PECO was also directed to develop a plan by January 1, 2014 that will allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from EGSs. PECO expects to file its plan by March 2013.

Smart Meter and Smart Grid Investments (Exelon and PECO). Pursuant to Act 129 and the follow-on Implementation Order of 2009 by the PAPUC, PECO began the first phase of its smart meter deployment in March 2012. The first phase calls for the installation of an AMI communications network and the deployment of 600,000 smart meters to communicate with that network. The first phase of smart meter deployment was estimated to cost $415 million.

Pursuant to the ARRA of 2009, PECO and the DOE entered into a Financial Assistance Agreement to extend PECO $200 million in SGIG funds. Of the $200 million in grant money, $140 million is being applied to the AMI technology deployment, including 600,000 smart meters in the first phase deployment. Therefore, the SGIG funds are being used to offset the impact to ratepayers of the smart meter deployment required by Act 129. As of September 30, 2012, PECO has received $130 million in reimbursements from the DOE for its smart meter deployment and other grid improvements. PECO's outstanding receivable from the DOE for reimbursable costs was $16 million as of September 30, 2012, which has been recorded in other accounts receivable, net on Exelon's and PECO's Consolidated Balance Sheets.

On August 15, 2012, PECO suspended its installation of smart meters for new customers based on a limited number of incidents involving overheating meters. Following its own internal investigation and additional scientific analysis and testing by independent experts completed after September 30, 2012, PECO announced its decision to resume meter deployment work on October 9, 2012. PECO will replace 186,000 previously installed meters with Landis+Gyr (L+G) meters by the end of November 2012 and will use L+G meters for the remainder of the first phase deployment.

As of September 30, 2012, the carrying value of the original meters, including installation and removal costs, owned by PECO was approximately $18 million, net of approximately $16 million of reimbursements from the DOE. PECO does not expect the change in vendor to impact its eligibility for the $200 million in SGIG funds. PECO is seeking and anticipates full recovery of these meter and other incremental costs incurred in response to the overheating incidents, and, therefore, expects this matter will not have a material impact on PECO's results of operations, cash flows or financial position.

Energy Efficiency Program (Exelon and PECO). PECO's PAPUC-approved EE&C Plan has a four-year term that began on June 1, 2009 and sets forth how PECO will meet the various reduction targets established by Act 129's EE&C provisions. In addition to energy consumption reductions, Act 129 requires Pennsylvania electric distribution companies to reduce peak demand by a minimum of 4.5% of their annual system peak demand in the 100 hours of highest demand. The peak demand period ended on September 30, 2012 and PECO will report its compliance with the reduction targets in a filing with the PAPUC by December 2012.

On August 2, 2012, the PAPUC issued its Phase II EE&C implementation order. The order provides energy consumption reduction requirements for the second phase of Act 129 EE&C programs, which will go into effect on June 1, 2013, but defers a decision on peak demand reduction requirements until the first quarter of 2013. The order tentatively establishes PECO’s three year cumulative consumption reduction target at 2.9%. The order also provides the opportunity for any electric utility to challenge its proposed target in an evidentiary hearing, which PECO requested on August 20, 2012. In addition, on September 4, 2012, PECO filed a Petition for Reconsideration of the terms of the PAPUC’s implementation order for Phase II, which was subsequently denied.

Pursuant to the Phase II implementation order, PECO filed its three year EE&C Phase II plan with the PAPUC on November 2, 2012. The plan sets forth how PECO will reduce electric consumption by at least 2.9% in its service territory for the period June 1, 2013 through May 31, 2016, adjusted for weather and extraordinary loads. The implementation order permits PECO to apply any excess savings achieved during Phase I against its Phase II consumption reduction targets, with no reduction to its Phase II budget. In accordance with the Act 129 Phase II implementation order, at least 10% and 4.5% of the total consumption reductions must be through programs directed toward PECO’s public and low income sectors, respectively. If PECO fails to achieve the required reductions in consumption, it will be subject to civil penalties of up to $20 million, which would not be recoverable from ratepayers. Act 129 mandates that that the total cost of the plan may not exceed 2% of the electric company’s total annual revenue as of December 31, 2006.

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 as of September 30, 2012.

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 October 12, 2012, the PAPUC approved PECO’s second DSP plan, which includes several new programs to continue PECO’s support of retail market competition in Pennsylvania in accordance with the order issued by the PAPUC on December 15, 2011. 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. Further, the PAPUC issued a Secretarial Letter on September 27, 2012, outlining its proposed end-state for default service, which included short-term contracts for all default service providers of approximately 3 months and the inclusion of CAP customers in the customer choice programs. A Tentative Order on these proposals is expected to be issued in November 2012.

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' 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.

2010 Natural Gas Distribution Rate Case (Exelon and PECO). PECO's 2010 natural gas distribution rate case settlement approved by the PAPUC stipulates that the expected cash benefit resulting from the application of new tax repairs deduction methodologies for 2010 and prior tax years must be refunded to customers over a seven-year period. In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The expected total refund to customers for the tax cash benefit from the application of the new method to costs incurred prior to 2011 is $54 million, for which PECO has recorded a regulatory liability that is reflected on Exelon's and PECO's Consolidated Balance Sheets as of September 30, 2012. This amount is subject to adjustment based on the outcome of IRS examinations. Credits will be reflected in customer bills beginning January 1, 2013. The prospective tax benefits claimed as a result of the new methodology will be reflected in tax expense in the year in which they are 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 10 — Income Taxes for additional information.

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 are being recovered over a 5-year period which began in 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 September 30, 2012, BGE had received $126 million in reimbursements from the DOE. As of September 30, 2012, BGE's outstanding receivable from the DOE for reimbursable costs was $13 million, which has been recorded in other accounts receivable, net on Exelon's and BGE's Consolidated Balance Sheets.

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. Depending on the precise terms of the CfD, the eventual market conditions, and the manner of cost recovery, the CfD could have a material adverse 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 were both denied by the U.S. District Court on August 3, 2012. 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. All cases have now been consolidated and will be heard together by the Circuit Court for Baltimore City in the first quarter of 2013.

2012 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 27, 2012, BGE filed an application for increases to its electric and gas base rates with the MDPSC. The requested rate of return on equity in the application is 10.5%. On October 22, 2012, BGE filed an updated application to request an increase of $131 million and $45 million to its electric and gas base rates, respectively. 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

Annual Transmission Formula Rate Update (Exelon, ComEd and BGE). ComEd’s most recent annual formula rate update filed in May 2012 reflects actual 2011 expenses and investments plus forecasted 2012 capital additions. The update resulted in a revenue requirement of $450 million offset by a $5 million reduction related to the reconciliation of 2011 actual costs for a net revenue requirement of $445 million. This compares to the May 2011 updated revenue requirement of $438 million offset by a $16 million reduction related to the reconciliation of 2010 actual costs for a net revenue requirement of $422 million. The increase in the revenue requirement was primarily driven by higher depreciation, pension and operating and maintenance costs, and the absence of a one-time credit that had been included in 2010 costs. The 2012 net revenue requirement became effective June 1, 2012 and is recovered over the period extending through May 31, 2013. The regulatory liability associated with the true-up is being amortized as the associated amounts are refunded.

ComEd’s updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.91%, a decrease from the 9.10% return for the prior year, primarily due to lower debt costs. As part of the FERC-approved settlement of ComEd’s 2007 rate case, the return on common equity is 11.5% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the formula transmission rate is currently capped at 55%.

PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd, PECO and BGE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit.

ComEd, PECO and BGE are committed to the construction of transmission facilities under their operating agreements with PJM to maintain system reliability. ComEd, PECO and BGE will work with PJM to continue to evaluate the scope and timing of any required construction projects. ComEd, PECO and BGE’s RTEP baseline project commitments changed as of September 30, 2012 from December 31, 2011 as follows:

- ComEd increased its RTEP baseline project commitments by $124 million for the nine months ended September 30, 2012, reflecting increases of $8 million, $57 million, $9 million, $20 million, $25 million and $5 million for 2012, 2013, 2014, 2015, 2016 and 2017, respectively.

- PECO increased its RTEP baseline project commitments by $86 million for the nine months ended September 30, 2012, reflecting increases of $6 million, $9 million, $11 million, $13 million, $21 million and $26 million for 2012, 2013, 2014, 2015, 2016 and 2017, respectively.
- BGE's increased its RTEP baseline project commitments by $165 million for the nine months ended September 30, 2012, reflecting (decreases)/increases of $(32) million, $(20) million, $44 million, $115 million, $52 million and $6 million for 2012, 2013, 2014, 2015, 2016, and 2017, respectively.

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. FERC generally denied rehearing, and the FERC orders have been appealed to the Third Circuit Court of Appeals. A resolution of that appeal is not expected until sometime in 2013.

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. In late September, PJM announced to all of its stakeholders that a group of its stakeholders had developed a proposal addressing the shortcomings of the current MOPR. PJM plans to have its stakeholders review and consider these proposed MOPR changes in October and November with a potential vote on these proposed MOPR changes in late November 2012. PJM would need to obtain approval from the FERC prior to implementing any changes. Exelon was actively involved in the process through which the MOPR changes were developed, supports the changes and intends to continue to work with PJM and its stakeholders to obtain necessary approvals.

License Renewals (Exelon and Generation). On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Muddy Run Pumped Storage Project and the Conowingo Hydroelectric Project. The FERC review process is scheduled to be completed by August 31, 2014 and September 1, 2014, when the current Conowingo and Muddy Run licenses expire.

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.

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

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

September 30, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits(a)	$ 264	$ 3,499	$ —	$ —	$ 2	$ —	$ 1	$ —
Deferred income taxes	13	1,346	5	62	—	1,220	8	64
AMI and smart meter programs	2	54	2	5	—	24	—	25
Under-recovered distribution service costs	—	119	—	119	—	—	—	—
Debt costs	14	71	11	65	3	6	2	9
Fair value of BGE long-term debt(b)	43	226	—	—	—	—	—	—
Fair value of BGE supply contract(c)	94	31	—	—	—	—	—	—
Severance	30	36	25	19	—	—	5	17
Asset retirement obligations	—	84	—	59	—	25	—	—
MGP remediation costs	65	227	58	190	6	35	1	2
RTO start-up costs	3	3	3	3	—	—	—	—
Under-recovered electric universal service fund costs	8	—	—	—	8	—	—	—
Financial swap with Generation	—	—	352	—	—	—	—	—
Renewable energy and associated RECs	17	53	17	53	—	—	—	—
Under-recovered energy and transmission costs	62	—	22	—	7(d)	—	33	—
DSP Program costs	2	2	—	—	2	2	—	—
DSP II Program costs	—	2	—	—	—	2	—	—
Deferred storm costs	3	7	—	—	—	—	3	7
Electric generation-related regulatory asset	16	44	—	—	—	—	16	44
Rate stabilization deferral	65	244	—	—	—	—	65	244
Energy efficiency and demand response programs	55	117	—	—	—	—	55	117
Other	30	27	16	14	14	9	—	5
Total regulatory assets	$ 786	6,192	$ 511	$ 589	$ 42	$ 1,323	$ 189	$ 534

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

September 30, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Nuclear decommissioning	$ —	$ 2,383	$ —	$ 2,021	$ —	$ 362	$ —	$ —
Removal costs	94	1,397	73	1,185	—	—	21	212
Energy efficiency and demand response programs	82	33	37	—	45	33	—	—
Electric distribution tax repairs	18	138	—	—	18	138	—	—
Gas distribution tax repairs	5	49			5	49		
Over-recovered distribution service costs	45	—	45	—	—	—	—	—
Over-recovered uncollectible accounts	10	—	10	—	—	—	—	—
Over-recovered energy and transmission costs	39	—	7	—	32(e)	—	—	—
Over-recovered gas universal service fund costs	3	—	—	—	3	—	—	—
Over-recovered AEPS costs	1	—	—	—	1	—	—	—
Customer rate credit	1	—	—	—	—	—	1	—
Other	1	—	—	—	1	—	—	—
Total regulatory liabilities	$ 299	$ 4,000	$ 172	$ 3,206	$ 105	$ 582	$ 22	$ 212

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 September 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) Includes $5 million related to under-recovered electric transmission costs and $2 million related to under-recovered natural gas costs under the PGC as of September 30, 2012. The balance as of December 31, 2011 related to under-recovered electric transmission costs.
(e) Relates to the over-recovered electric supply costs under the GSA as of September 30, 2012. Includes $5 million related to the over-recovered natural gas costs under the PGC and $25 million related to the over-recovered electric supply costs under the GSA as of December 31, 2011.

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

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

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers. For retail suppliers participating in the utilities' consolidated billing, ComEd, PECO and BGE must purchase their customer accounts receivables. ComEd and BGE purchase receivables at a discount to primarily recover uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and permitted to recover uncollectible accounts expense from customers through distribution rates. 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 September 30, 2012 and December 31, 2011.

As of September 30, 2012	Exelon	ComEd	PECO	BGE
Purchased receivables(a)	$ 203	$ 56	$ 72	$ 75
Allowance for uncollectible accounts(b)	(18)	(6)	(7)	(5)
Purchased receivables, net	$ 185	$ 50	$ 65	$ 70

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 September 30, 2012	For the Period March 12, through September 30, 2012
Equity investment income	$ 58	$ 53
Amortization of basis difference in CENG	(57)	(131)
Total equity in earnings (losses) — CENG	$ 1	$ (78)

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

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

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

A subsidiary of Generation has an agreement 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 the CENG plants, which expires on December 31, 2014. The PSAA is a five-year agreement under which Generation provides scheduling, asset management and billing services to the CENG plants for a specified monthly fee. The charges for services reflect the cost of the service, with such cost not to exceed approximately $358,000 per month.

In addition to the PSAA, Exelon has a shared services agreement (SSA) with CENG, which expires in 2017. Under the SSA, BSC provides a variety of support services to CENG. The SSA 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 SSA 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	Income/(Expense) Three Months Ended September 30, 2012	Income/(Expense) For the Period March 12 through September 30, 2012	Income Statement Classification	Accounts Receivable/ (Accounts Payable) At September 30, 2012
PPA	$ (282)	$ (541)	Purchased power and fuel	$ (86)
PSAA	1	2	Operating revenues	—
SSA	14	30	Operating revenues	5

In May 2011, CENG issued an unsecured revolving promissory note to borrow up to an aggregate principal amount of $63 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% to Generation and 50% to EDF. As of September 30, 2012, CENG had borrowed $43 million from Generation. The unsecured promissory note matured on October 31, 2012, and all amounts due were paid in full as of that date.

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. 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.

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

The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required. Consistent with 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.

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.

On October 3, 2012, the ICC issued its Rehearing Order in response to ComEd's expedited rehearing request. The Rehearing Order adopted ComEd's position on the return on its pension asset resulting in an increase in ComEd's annual revenue requirement. See Note 4 — Regulatory Matters for further detail.

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 September 30, 2012 and December 31, 2011:

Exelon

	September 30, 2012				December 31, 2011	
	Carrying Amount	Fair Value			Carrying Amount	Fair Value
		Level 1	Level 2	Level 3		
Short-term liabilities	$ 289	$ 4	$ 285	$ —	$ 737	$ 737
Long-term debt (including amounts due within one year)	18,715	—	20,762	38	12,627	14,488
Long-term debt to financing trusts	649	—	650	—	390	358
SNF obligation	1,020	—	780	—	1,019	886
Preferred securities of subsidiary	87	—	83	—	87	79

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

Generation

	September 30, 2012				December 31, 2011	
	Carrying Amount	Fair Value			Carrying Amount	Fair Value
		Level 1	Level 2	Level 3		
Short-term liabilities	$ 11	$ —	$ 11	$ —	$ 2	$ 2
Long-term debt (including amounts due within one year)	7,383	—	7,839	20	3,677	4,231
SNF obligation	1,020	—	780	—	1,019	886

ComEd

	September 30, 2012				December 31, 2011	
	Carrying Amount	Fair Value			Carrying Amount	Fair Value
		Level 1	Level 2	Level 3		
Short-term liabilities	$ 35	$ —	$ 35	$ —	$ —	$ —
Long-term debt (including amounts due within one year)	5,217	—	6,297	18	5,665	6,540
Long-term debt to financing trust	206	—	208	—	206	184

PECO

	September 30, 2012				December 31, 2011	
	Carrying Amount	Fair Value			Carrying Amount	Fair Value
		Level 1	Level 2	Level 3		
Short-term liabilities	$ 225	$ —	$ 225	$ —	$ 225	$ 225
Long-term debt (including amounts due within one year)	2,322	—	2,682	—	1,972	2,295
Long-term debt to financing trusts	184	—	180	—	184	174
Preferred securities	87	—	83	—	87	79

BGE

	September 30, 2012				December 31, 2011	
	Carrying Amount	Fair Value			Carrying Amount	Fair Value
		Level 1	Level 2	Level 3		
Long-term debt (including amounts due within one year)	2,210	—	2,547	—	2,101	2,377
Long-term debt to financing trusts	258	—	264	—	258	256

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of short-term borrowings (Level 2), short-term notes payable related to PECO's accounts receivable agreement (Level 2), and dividends payable (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 2025 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2025.

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 nine months ended September 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 September 30, 2012 and December 31, 2011:

As of September 30, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 1,117	$ —	$ —	$ 1,117
Nuclear decommissioning trust fund investments				
Cash equivalents	319	—	—	319
Equity				
Equity securities	1,452	—	—	1,452
Commingled funds	—	1,906	—	1,906
Equity funds subtotal	1,452	1,906	—	3,358
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,100	—	—	1,100
Debt securities issued by states of the United States and political subdivisions of the states	—	355	—	355
Debt securities issued by foreign governments	—	84	—	84
Corporate debt securities	—	1,734	—	1,734
Federal agency mortgage-backed securities	—	31	—	31
Commercial mortgage-backed securities (non-agency)	—	47	—	47
Residential mortgage-backed securities (non-agency)	—	15	—	15
Mutual funds	—	9	—	9
Fixed income subtotal	1,100	2,275	—	3,375
Direct lending securities	—	—	70	70
Other debt obligations	—	16	—	16
Nuclear decommissioning trust fund investments subtotal(b)	2,871	4,197	70	7,138
Pledged assets for Zion Station decommissioning				
Equity				
Equity securities	21	—	—	21
Commingled funds	—	20	—	20
Equity funds subtotal	21	20	—	41
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	78	15	—	93
Debt securities issued by states of the United States and political subdivisions of the states	—	58	—	58
Corporate debt securities	—	260	—	260
Federal agency mortgage-backed securities	—	60	—	60
Commercial mortgage-backed securities (non-agency)	—	6	—	6
Commingled funds	—	43	—	43
Fixed income subtotal	78	442	—	520
Direct lending securities	—	—	64	64
Other debt obligations	—	1	—	1
Pledged assets for Zion Station decommissioning subtotal(c)	99	463	64	626

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

As of September 30, 2012	Level 1	Level 2	Level 3	Total
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds(d)(e)	69	—	—	69
Rabbi trust investments subtotal	71	—	—	71
Commodity mark-to-market derivative assets				
Economic hedges	994	3,872	666	5,532
Proprietary trading	1,631	3,070	140	4,841
Effect of netting and allocation of collateral(f)	(2,597)	(5,695)	(238)	(8,530)
Commodity mark-to-market assets subtotal(g)	28	1,247	568	1,843
Interest rate mark-to-market derivative assets	—	125	—	125
Other investments	2	—	17	19
Total assets	4,188	6,032	719	10,939
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,225)	(2,814)	(351)	(4,390)
Proprietary trading	(1,678)	(2,881)	(222)	(4,781)
Effect of netting and allocation of collateral(f)	2,772	5,336	229	8,337
Commodity mark-to-market liabilities subtotal(g)(h)	(131)	(359)	(344)	(834)
Interest rate mark-to-market derivative liabilities	—	(95)	—	(95)
Deferred compensation	—	(101)	—	(101)
Total liabilities	(131)	(555)	(344)	(1,030)
Total net assets	$ 4,057	$ 5,477	$ 375	$ 9,909

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

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
Direct lending securities	—	—	13	13
Other debt obligations	—	18	—	18
Nuclear decommissioning trust fund investments subtotal(b)	2,851	3,700	13	6,564
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

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

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(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net assets (liabilities) of $2 million and $(57) million at September 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 $5 million and $9 million at September 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.
(d) The mutual funds held by the Rabbi trusts include $54 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 $28 million and $25 million of the cash surrender value of life insurance investments at September 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 $175 million, $(359) million and $(9) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of September 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 $352 million and $0 million at September 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 $17 million and $53 million at September 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 nine months ended September 30, 2012 and 2011:

Three Months Ended September 30, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of June 30, 2012	$ 54	$ 59	$ 295	$ 17	$425
Total realized / unrealized gains (losses)					
Included in net income	—	—	(97)(a)	—	(97)
Included in regulatory assets	2	—	41(b)	—	43
Included in payable for Zion Station decommissioning	—	1	—	—	1
Change in collateral	—	—	(15)	—	(15)
Purchases, sales, issuances and settlements Purchases(c)	14	4	—	—	18
Balance as of September 30, 2012	$ 70	$ 64	$ 224	$ 17	$375
The amount of total losses included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the three months ended September 30, 2012	$ —	$ —	$ (42)	$ —	$ (42)

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

Nine Months Ended September 30, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2011	$ 13	$ 37	$ 17	$ —	$ 67
Total realized / unrealized gains (losses)					
Included in net income	—	—	(157)(a)	—	(157)
Included in other comprehensive income	—	—	1	—	1
Included in regulatory assets	2	—	36(b)	—	38
Change in collateral	—	—	(7)	—	(7)
Purchases, sales, issuances and settlements					
Purchases(c)	55	36	329	17	437
Sales	—	(9)	—	—	(9)
Transfers into Level 3	—	—	(34)	—	(34)
Transfers out of Level 3	—	—	39	—	39
Balance as of September 30, 2012	$ 70	$ 64	$ 224	$ 17	$ 375
The amount of total losses included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the nine months ended September 30, 2012	$ —	$ —	$ (16)	$ —	$ (16)

(a) Includes the reclassification of $55 million and $141 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and nine months ended September 30, 2012.
(b) Excludes $35 million of decreases in fair value and $86 million of increases in fair value and $119 million and $427 million of realized losses due to settlements for the three and nine months ended September 30, 2012 of Generation's financial swap contract with ComEd, which eliminates upon consolidation in Exelon's Consolidated Financial Statements.
(c) Includes $323 million of fair value from contracts and $17 million of other investments acquired as a result of the merger.

Three Months Ended September 30, 2011	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Total
Balance as of June 30, 2011	$ —	$ 34	$ (16)	$ 18
Total realized / unrealized gains (losses)				
Included in income	—	—	(8)(a)	(8)
Included in other comprehensive income	—	—	(15)(b)	(15)
Included in regulatory assets	—	—	(18)	(18)
Included in payable for Zion Station decommissioning	—	(3)	—	(3)
Change in collateral	—	—	8	8
Purchases, sales, issuances and settlements				
Purchases	6	17	—	23
Sales	—	(10)	—	(10)
Transfers out of Level 3	—	—	24	24
Balance as of September 30, 2011	$ 6	$ 38	$ (25)	$ 19
The amount of total gains included in income attributed to the change in unrealized losses related to assets and liabilities held for the three months ended September 30, 2011	$ —	$ —	$ (5)	$ (5)

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

Nine Months Ended September 30, 2011	Nuclear Decommissioning Trust Fund Investments	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 other comprehensive income	—	—	(27)(a)	(27)
Included in regulatory assets	—	—	(51)(b)	(51)
Change in collateral	—	—	15	15
Purchases, sales, issuances and settlements				
Purchases	6	60	4	70
Sales	—	(22)	—	(22)
Transfers out of Level 3	—	—	(16)	(16)
Balance as of September 30, 2011	$ 6	$ 38	$ (25)	$ 19
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the nine months ended September 30, 2011	$ —	$ —	$ 18	$ 18

(a) Includes the reclassification of $4 million and $19 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and nine months ended September 30, 2011, respectively.

(b) Excludes $7 million and $4 million of decreases in fair value and $88 million and $309 million of realized losses due to settlements associated with Generation’s financial swap contract with ComEd and $3 million of changes in the fair value of Generation’s block contracts with PECO for the nine months ended September 30, 2011. All items eliminate upon consolidation if Exelon’s Consolidated Financial Statements.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2012 and 2011:

	Operating Revenue	Purchased Power and Fuel
Total gains (losses) included in income for the three months ended September 30, 2012	$ (106)	$ 9
Total gains (losses) included in income for the nine months ended September 30, 2012	$ (195)	$ 38
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2012	$ (48)	$ 6
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2012	$ (45)	$ 29

	Operating Revenue	Purchased Power and Fuel
Total gains (losses) included in income for the three months ended September 30, 2011	$ (5)	$ (3)
Total gains (losses) included in income for the nine months ended September 30, 2011	$ 2	$ (2)
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2011	$ 1	$ (6)
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2011	$ 22	$ (4)

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

Generation

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

As of September 30, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 518	$ —	$ —	$ 518
Nuclear decommissioning trust fund investments				
Cash equivalents	319	—	—	319
Equity				
Equity securities	1,452	—	—	1,452
Commingled funds	—	1,906	—	1,906
Equity funds subtotal	1,452	1,906	—	3,358
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,100	—	—	1,100
Debt securities issued by states of the United States and political subdivisions of the states	—	355	—	355
Debt securities issued by foreign governments	—	84	—	84
Corporate debt securities	—	1,734	—	1,734
Federal agency mortgage-backed securities	—	31	—	31
Commercial mortgage-backed securities (non-agency)	—	47	—	47
Residential mortgage-backed securities (non-agency)	—	15	—	15
Mutual funds	—	9	—	9
Fixed income subtotal	1,100	2,275	—	3,375
Direct lending securities	—	—	70	70
Other debt obligations	—	16	—	16
Nuclear decommissioning trust fund investments subtotal(b)	2,871	4,197	70	7,138
Pledged assets for Zion Station decommissioning				
Equity				
Equity securities	21	—	—	21
Commingled funds	—	20	—	20
Equity funds subtotal	21	20	—	41
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	78	15	—	93
Debt securities issued by states of the United States and political subdivisions of the states	—	58	—	58
Corporate debt securities	—	260	—	260
Federal agency mortgage-backed securities	—	60	—	60
Commercial mortgage-backed securities (non-agency)	—	6	—	6
Commingled funds	—	43	—	43
Fixed income subtotal	78	442	—	520
Direct lending securities	—	—	64	64
Other debt obligations	—	1	—	1

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

As of September 30, 2012	Level 1	Level 2	Level 3	Total
Pledged assets for Zion Station decommissioning subtotal(c)	99	463	64	626
Rabbi trust investments				
Cash equivalents	1	—	—	1
Mutual funds(d)(e)	13	—	—	13
Rabbi trust investments subtotal	14	—	—	14
Commodity mark-to-market derivative assets				
Economic hedges	994	3,872	1,018	5,884
Proprietary trading	1,631	3,070	140	4,841
Effect of netting and allocation of collateral(f)	(2,597)	(5,695)	(238)	(8,530)
Commodity mark-to-market assets subtotal(g)	28	1,247	920	2,195
Interest Rate mark-to-market derivative assets	—	111	—	111
Other investments	2	—	17	19
Total assets	3,532	6,018	1,071	10,621
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,225)	(2,814)	(281)	(4,320)
Proprietary trading	(1,678)	(2,881)	(222)	(4,781)
Effect of netting and allocation of collateral(f)	2,772	5,336	229	8,337
Commodity mark-to-market liabilities subtotal	(131)	(359)	(274)	(764)
Interest rate mark-to-market derivative liabilities	—	(95)	—	(95)
Deferred compensation	—	(27)	—	(27)
Total liabilities	(131)	(481)	(274)	(886)
Total net assets	$ 3,401	$ 5,537	$ 797	$ 9,735

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

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
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
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

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

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(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net assets (liabilities) of $2 million and $(57) million at September 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 $5 million and $9 million at September 30, 2012 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.
(d) The $13 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.
(e) Excludes $8 million and $7 million of the cash surrender value of life insurance investments at September 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 $175 million, $(359) million and $(9) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of September 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 $352 million and $0 million at September 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 nine months ended September 30, 2012 and 2011:

Three Months Ended September 30, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of June 30, 2012	$ 54	$ 59	$ 912	17	$1,042
Total unrealized / realized gains (losses)					
Included in income	—	—	(112)(a)	—	(112)
Included in other comprehensive income	—	—	(139)(b)	—	(139)
Included in noncurrent payables to affiliates	2	—	—	—	2
Included in payable for Zion Station decommissioning	—	1	—	—	1
Change in collateral	—	—	(15)	—	(15)
Purchases, sales, issuances and settlements					
Purchases(c)	14	4	—	—	18
Balance as of September 30, 2012	$ 70	$ 64	$ 646	$ 17	$ 797
The amount of total losses included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the three months ended September 30, 2012	$ —	$ —	$ (77)	$ —	$ (77)

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

Nine Months Ended September 30, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2011	$ 13	$ 37	$ 817	—	$ 867
Total unrealized / realized gains (losses)					
Included in income	—	—	(187)(a)	—	(187)
Included in other comprehensive income	—	—	(311)(b)	—	(311)
Included in noncurrent payables to affiliates	2	—	—	—	2
Change in collateral	—	—	(7)	—	(7)
Purchases, sales, issuances and settlements					
Purchases(c)	55	36	329	17	437
Sales	—	(9)	—	—	(9)
Transfers into Level 3	—	—	(34)		(34)
Transfers out of Level 3	—	—	39	—	39
Balance as of September 30, 2012	$ 70	$ 64	$ 646	$ 17	$ 797
The amount of total losses included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the nine months ended September 30, 2012	$ —	$ —	$ (77)	$ —	$ (77)

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

(b) Includes $35 million of decreases in fair value and $86 million of increases in fair value and realized losses due to settlements of $119 million and $427 million associated with Generation’s financial swap contract with ComEd for the three and nine months ended September 30, 2012, respectively. This position was 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 $323 million of fair value from contracts and $17 million of other investments acquired as a result of the merger.

Three Months Ended September 30, 2011	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Total
Balance as of June 30, 2011	$ —	$ 34	$ 776	$ 810
Total realized / unrealized gains (losses)				
Included in income	—	—	(8)(a)	(8)
Included in other comprehensive income	—	—	(110)(b)	(110)
Included in payable for Zion Station decommissioning	—	(3)	—	(3)
Changes in collateral	—	—	8	8
Purchases, sales, issuances and settlements				
Purchases	6	17	—	23
Sales	—	(10)	—	(10)
Transfers out of Level 3 — Asset	—	—	24	24
Balance as of September 30, 2011	$ 6	$ 38	$ 690	$ 734
The amount of total gains included in income attributed to the change in unrealized (losses) related to assets and liabilities held for the three months ended September 30, 2011	$ —	$ —	$ (5)	$ (5)

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

Nine Months Ended September 30, 2011	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Total
Balance as of December 31, 2010	$ —	$ —	$ 1,030	$1,030
Total realized / unrealized gains (losses)				
Included in other comprehensive income	—	—	(343)(b)	(343)
Changes in collateral	—	—	15	15
Purchases	6	60	4	70
Sales	—	(22)	—	(22)
Transfers out of Level 3 — Liability	—	—	(16)	(16)
Balance as of September 30, 2011	$ 6	$ 38	$ 690	$ 734
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the nine months ended September 30, 2011	$ —	$ —	$ 18	$ 18

(a) Includes the reclassification of $4 million and $19 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and nine months ended September 30, 2011, respectively.

(b) Includes $7 million and $4 million of decreases in fair value realized losses reclassified from OCI due to settlements of $88 million and $309 million associated with Generation's financial swap contract with ComEd for the three and nine months ended September 30, 2011, and $3 million of decreases in fair value due to settlement of Generation's block contracts with PECO for the three and nine months ended September 30, 2011. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2012 and 2011:

	Operating Revenue	Purchased Power and Fuel
Total gains (losses) included in income for the three months ended September 30, 2012	$ (121)	$ 9
Total gains (losses) included in income for the nine months ended September 30, 2012	$ (225)	$ 38
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2012	$ (83)	$ 6
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2012	$ (95)	$ 18

	Operating Revenue	Purchased Power and Fuel
Total gains (losses) included in income for the three months ended September 30, 2011	$ (5)	$ (3)
Total gains (losses) included in income for the nine months ended September 30, 2011	$ 2	$ (2)
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2011	$ 1	$ (6)
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2011	$ 22	$ (4)

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

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ComEd

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

As of September 30, 2012	Level 1	Level 2	Level 3	Total
Assets				
Rabbi trust investments				
Mutual funds	9	—	—	9
Rabbi trust investment subtotal	9	—	—	9
Total assets	9	—	—	9
Liabilities				
Deferred compensation obligation	—	(9)	—	(9)
Mark-to-market derivative liabilities(b)(c)	—	—	(422)	(422)
Total liabilities	—	(9)	(422)	(431)
Total net assets (liabilities)	$ 9	$ (9)	$(422)	$(422)

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 $352 million and $0 million at September 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 $17 million and $53 million at September 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.

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

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

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

Nine Months Ended September 30, 2012	Mark-to-Market Derivatives
Balance as of December 31, 2011	$ (800)
Total realized / unrealized gains included in regulatory assets(a)(b)	378
Balance as of September 30, 2012	$ (422)

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

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

Three Months Ended September 30, 2011	Mark-to-Market Derivatives
Balance as of June 30, 2011	$ (788)
Total realized / unrealized gains included in regulatory assets(a)(b)	76
Balance as of September 30, 2011	$ (712)

Nine Months Ended September 30, 2011	Mark-to-Market Derivatives
Balance as of December 31, 2010	$ (971)
Total realized / unrealized gains included in regulatory assets(a)(b)	259
Balance as of September 30, 2011	$ (712)

(a) Includes $7 million and $4 million of increases in fair value and $88 million and $309 million of realized gains due to settlements associated with ComEd's financial swap contract with Generation for the three and nine months ended September 30, 2011, respectively. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

(b) Includes $19 million and $54 million of decreases in fair value of floating-to-fixed energy swap contracts with unaffiliated suppliers for the three and nine months ended September 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 September 30, 2012 and December 31, 2011:

As of September 30, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 528	$ —	$ —	$528
Rabbi trust investments — mutual funds(b)(c)	9	—	—	9
Total assets	537	—	—	537
Liabilities				
Deferred compensation obligation	—	(18)	—	(18)
Total liabilities	—	(18)	—	(18)
Total net assets (liabilities)	$ 537	$ (18)	$ —	$519

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 $14 million and $13 million of the cash surrender value of life insurance investments at September 30, 2012 and December 31, 2011, respectively.

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

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

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2011:

Three Months Ended September 30, 2011	Mark-to-Market Derivatives
Balance as of June 30, 2011	$ (4)
Total realized gains included in regulatory assets	1
Balance as of September 30, 2011	$ (3)

Nine Months Ended September 30, 2011	Mark-to-Market Derivatives
Balance as of December 31, 2010	$ (9)
Total realized gains included in regulatory assets	6(a)
Balance as of September 30, 2011	$ (3)

(a) Includes an increase of $3 million related to the settlement of PECO's block contract with Generation for the nine months ended September 30, 2011, 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 September 30, 2012 and December 31, 2011:

As of September 30, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 52	$ —	$ —	$ 52
Rabbi trust investments — mutual funds	5	—	—	5
Total assets	57	—	—	57
Liabilities				
Deferred compensation obligation	—	(5)	—	(5)
Total liabilities	—	(5)	—	(5)
Total net assets (liabilities)	$ 57	$ (5)	$ —	$ 52

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

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

Valuation Techniques Used to Determine Fair Value

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

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

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to 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 and verified by risk management considering published exchange transaction prices, executed bilateral transactions,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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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 $4.00 and $0.25 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 include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk. The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade	Fair Value at September 30, 2012(d)	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives — Economic Hedges (Generation)(a)	$ 386	Discounted Cash Flow	Forward power price	$8 - $76
			Forward gas price	$3.04 - $6.35
		Option Model	Volatility percentage	26% - 120%
Mark-to-market derivatives — Proprietary trading (Generation)(a)	$ (83)	Discounted Cash Flow	Forward power price	$13 - $108
		Option Model	Volatility percentage	22% - 67%
Mark-to-market derivatives — Transactions with affiliates (Generation and ComEd) (b)	$ 352	Discounted Cash Flow	Marketability reserve	7.3% - 8.7%
Mark-to-market derivatives (ComEd)	$ (70)	Discounted Cash Flow	Forward heat rate (c)	8.5% - 9.5%
			Marketability reserve	3.5% - 8.3%
			Renewable factor	80% - 126%

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 $352 million, related to the fair value of the five-year financial swap contract between Generation and ComEd, which eliminates in consolidation.
c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
d) The fair values below do not include cash collateral held on level three positions of $9 million as of September 30, 2012.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation's commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give 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. 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. 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 September 30, 2012, the percentage of expected generation hedged was 98%-101%, 87%-90%, 55%-58% and 20%-23% for 2012, 2013, 2014 and 2015, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity 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 2012 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2012 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 30% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

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

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading activities, which included settled physical sales volumes of 4,352 GWh and 9,981 GWh for the three and nine months ended September 30, 2012, respectively, and 1,679 GWh and 4,508 GWh for the three and nine months ended September 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.

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 approximately $ 2 million decrease in Exelon Consolidated pre-tax income for the nine months ended September 30, 2012. Below is a summary of the interest rate hedges as of September 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)	$ —	$ 3	$ 19	$ 22	$ —	$ 22
Mark-to-market derivative assets (Noncurrent Assets)	42	10	37	89	14	103
Total mark-to-market derivative assets	$ 42	$ 13	$ 56	$ 111	$ 14	$ 125
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (2)	$ (19)	$ (22)	$ —	$ (22)
Mark-to-market derivative liabilities (Noncurrent Liabilities)	(36)	—	(37)	(73)	—	(73)
Total mark-to-market derivative liabilities	$ (37)	$ (2)	$ (56)	$ (95)	$ —	$ (95)
Total mark-to-market derivative net assets (liabilities)	$ 5	$ 11	$ —	$ 16	$ 14	$ 30

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

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the 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.

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 Nine Months Ended September 30,		Gain (Loss) on Borrowings Nine Months Ended September 30,	
Income Statement Classification	2012	2011	2012	2011
Interest expense(a)	$ (3)	$ 1	$ (6)	$ (1)

(a) For the nine months ended September 30, 2012, the loss on the swaps in the table above includes pre-tax losses of $9 million, not related to changes in benchmark interest rates and is excluded from hedge ineffectiveness.

At September 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 nine months ended September 30, 2012 and September 30, 2011, the impact of loss on the results of operations as a result of ineffectiveness from fair value hedges was immaterial.

At September 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 September 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 its first loan advance on April 5, 2012, and several additional advances subsequently, as described in Note 9 — Debt and Credit Agreements. As of September 30, 2012, Generation has entered into a series of fixed-to-floating interest rate swaps with an aggregated notional amount of $119 million, 75% of the loan advance amount to offset portions of the original interest rate hedge, which are de-designated as a cash flow hedge. The remaining cash flow hedge has a notional amount of $365 million. At September 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 $32 million.

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 September 30, 2012 and expire in 2027. Upon the closing of the merger with Constellation, the swaps were re-designated as cash flow hedges. At September 30, 2012, the subsidiary had a $4 million non-current derivative liability related to these swaps.

During the three and nine months ended September 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.

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

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

	Generation				ComEd	Other	Exelon
Derivatives	Economic Hedges(a)	Proprietary Trading	Collateral and Netting(b)	Subtotal (c)	Economic Hedges (a)(d)	Intercompany Eliminations (a)	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 3,399	$ 3,694	$ (6,187)	$ 906	$ —	$ —	$ 906
Mark-to-market derivative assets with affiliate (current assets)	352	—	—	352	—	(352)	—
Mark-to-market derivative assets (noncurrent assets)	2,133	1,147	(2,343)	937	—	—	937
Total mark-to-market derivative assets	$ 5,884	$ 4,841	$ (8,530)	$2,195	$ —	$ (352)	$ 1,843
Mark-to-market derivative liabilities (current liabilities)	$ (2,951)	$ (3,675)	$ 6,144	$ (482)	$ (17)	$ —	$ (499)
Mark-to-market derivative liability with affiliate (current liabilities)	—	—	—	—	(352)	352	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,369)	(1,106)	2,193	(282)	(53)	—	(335)
Total mark-to-market derivative liabilities	$ (4,320)	$ (4,781)	$ 8,337	$ (764)	$ (422)	$ 352	$ (834)
Total mark-to-market derivative net assets (liabilities)	$ 1,564	$ 60	$ (193)	$1,431	$ (422)	$ —	$ 1,009

(a) Includes current assets for Generation and current liabilities for ComEd of $352 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 $92 million and $263 million, respectively, and current and noncurrent liabilities are shown net of collateral of $(49) million and $(113) million, respectively. The total cash collateral received, net of cash collateral posted and offset against mark-to-market assets and liabilities was $193 million at September 30, 2012.
(d) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

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

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

(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.

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

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 $906 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 $383 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 September 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 nine months ended September 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	
Three Months Ended September 30, 2012	**Income Statement Location**	**Generation Energy-Related Hedges**	**Exelon Total Cash Flow Hedges**
Accumulated OCI derivative gain at June 30, 2012		$ 923(a)(c)	$ 547
Reclassifications from accumulated OCI to net income	Operating Revenues	(171)(b)	(88)(d)
Ineffective portion recognized in income	Operating Revenues	—	—
Accumulated OCI derivative gain at September 30, 2012		$ 752(a)(c)	$ 459

(a) Includes $232 million and $315 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, as of September 30, 2012 and June 30, 2012, respectively.
(b) Includes $83 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c) Excludes $22 million of losses and $22 million of losses net of taxes, related to interest rate swaps and treasury rate locks for the three months ended September 30, 2012 and three months ended June 30, 2012.
(d) Includes $0 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.

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

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Nine Months Ended September 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)	301(d)
Reclassifications from accumulated OCI to net income	Operating Revenues	(608)(b)	(332)
Ineffective portion recognized in income	Operating Revenues	3	3
Accumulated OCI derivative gain at September 30, 2012		$ 752(a)(c)	$ 459

(a) Includes $232 million and $420 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, as of September 30, 2012 and December 31, 2011.
(b) Includes $276 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c) Excludes $22 million of losses and $10 million of losses, net of taxes, related to interest rate swaps and treasury locks for the nine months ended September 30, 2012 and year ended December 31, 2011, respectively.
(d) Includes $12 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.
(e) Includes $88 million of gains, net of taxes, related to the effective portion of changes in fair value of the five-year financial swap contract with ComEd through the date of de-designation prior to the merger.

Three Months Ended September 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 June 30, 2011		$ 688(a)(d)	$ 209
Effective portion of changes in fair value		(26)(b)	(26)
Reclassifications from accumulated OCI to net income	Operating Revenues	(98)(c)	(45)
Ineffective portion recognized in income	Purchased Power	7	7
Accumulated OCI derivative gain at September 30, 2011		$ 571(a)(d)	$ 145

(a) Includes $400 million and $458 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, $1 million of gains, net of taxes, related to the fair value of the block contracts with PECO as of September 30, 2011 and June 30, 2011, respectively.
(b) Includes a $5 million loss, 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 September 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 September 30, 2011 as the mark-to-market balances previously recorded will be amortized over the term of the contract.
(c) Includes a $53 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 for the three months ended September 30, 2011.
(d) Excludes $6 million loss and $2 million of gains, net of taxes, related to interest rate swaps and treasury rate locks as of September 30, 2011 and June 30, 2011, respectively.

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

Nine Months Ended September 30, 2011	Income Statement Location	Total Cash Flow Hedge OCI Activity, Net of Income Tax — Generation Energy-Related Hedges	Exelon Total Cash Flow Hedges
Accumulated OCI derivative gain at December 31, 2010		$ 1,011(a)(d)	$ 400
Effective portion of changes in fair value		(69)(b)	(73)
Reclassifications from accumulated OCI to net income	Operating Revenues	(373)(c)	(184)
Ineffective portion recognized in income	Purchased Power	2	2
Accumulated OCI derivative gain at September 30 2011		$ 571(a)(d)	$ 145

(a) Includes $400 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 September 30, 2011 and December 31, 2010, respectively.

(b) Includes a $2 million loss, net of taxes, related to the effective portion of changes in fair value of the five-year financial swap contract with ComEd for the nine months ended September 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 $187 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 nine months ended September 30, 2011.

(d) Excludes $6 million loss and $2 million of gains, net of taxes, related to interest rate swaps and treasury rate locks as of September 30, 2011 and December 31, 2010.

During the three and nine months ended September 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 $283 million and a $ 1,005 million pre-tax gain, respectively, and a $162 million and $617 million pre-tax gain for the three and nine months ended September 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 nine months ended September 30, 2012. There was no ineffectiveness for the three months ended September 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 $145 million and $548 million pre-tax gain for the three and nine months ended September 30, 2012, respectively, and a $74 million and $305 million pre-tax gain for the three and nine months ended 2011, respectively. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices were $5 million for the nine months ended September 30, 2012. There was no ineffectiveness for the three months ended September 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.

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

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 nine months ended September 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 3rd quarter of 2012, Generation completed a non-cash exchange by issuing a new in-the-money derivative with a new counterparty in exchange for novating to them existing in-the-money trades with the old counterparty for a total of $51 million. This transaction did not have any Income Statement effect to Generation. 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 September 30, 2012	Operating Revenues	Purchased Power and Fuel	Total	Operating Revenues(a)	Total
Change in fair value	$ (255)	$ 129	$(126)	$ 35	$ (91)
Reclassification to realized at settlement	20	122	142	(19)	123
Net mark-to-market gains (losses)	$ (235)	$ 251	$ 16	$ 16	$ 32

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

	Exelon and Generation		
Three Months Ended September 30, 2011 (As Reported)	Operating Revenues	Purchased Power and Fuel	Total
Change in fair value	$ —	$ 22	$ 22
Reclassification to realized at settlement	—	(101)	(101)
Net mark-to-market (losses)(b)	$ —	$ (79)	$ (79)

	Exelon and Generation		
Nine Months Ended September 30, 2011 (As Reported)	Operating Revenues	Purchased Power and Fuel	Total
Change in fair value	$ —	$ 13	$ 13
Reclassification to realized at settlement	—	(372)	(372)
Net mark-to-market (losses)(b)	$ —	$ (359)	$(359)

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

	Exelon and Generation		
Three Months Ended September 30, 2011 (Pro Forma)	Operating Revenues	Purchased Power and Fuel	Total
Change in fair value	$ 31	$ (9)	$ 22
Reclassification to realized at settlement	(105)	4	(101)
Net mark-to-market (losses)(b)	$ (74)	$ (5)	$ (79)

	Exelon and Generation		
Nine Months Ended September 30, 2011 (Pro Forma)	Operating Revenues	Purchased Power and Fuel	Total
Change in fair value	$ 44	$ (31)	$ 13
Reclassification to realized at settlement	(374)	2	(372)
Net mark-to-market (losses)(b)	$ (330)	$ (29)	$(359)

(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 nine months ended September 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 September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Change in fair value	Operating Revenue	$ (2)	$ 2	$ 12	$ 22
Reclassification to realized at settlement	Operating Revenue	25	(6)	57	(19)
Net mark-to-market gains	Operating Revenue	$ 23	$ (4)	$ 69	$ 3

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

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

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of September 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 $53 million, $53 million and $11 million, respectively.

Rating as of September 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	$ 1,968	$ 492	$ 1,476	—	$ —
Non-investment grade	46	25	21	—	—
No external ratings					
Internally rated — investment grade	501	16	485	1	267
Internally rated — non-investment grade	90	2	88	—	—
Total	$ 2,605	$ 535	$ 2,070	1	$ 267

Net Credit Exposure by Type of Counterparty	As of September 30, 2012
Investor-owned utilities, marketers and power producers	$ 902
Energy cooperatives and municipalities	710
Financial institutions	386
Other	72
Total	$ 2,070

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of September 30, 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 September 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 September 30, 2012, PECO had credit exposure of $8 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 September 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 September 30, 2012, BGE had credit exposure of $1 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third party suppliers.

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

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.

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

Credit-Risk Related Contingent Feature		September 30, 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)**
($2,720)	$2,156	($564)

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 $415 million and letters of credit posted of $973 million and cash collateral held of $607 million and letters of credit held of $109 million as of September 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 $2,004 million as of September 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.

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

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 September 30, 2012, Generation's swaps were in an asset position, with a fair value of $16 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 September 30, 2012, ComEd held neither cash nor letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of September 30, 2012, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. See Note 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 September 30, 2012, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of September 30, 2012, PECO could have been required to post approximately $30 million of collateral to its counterparties.

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

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

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of September 30, 2012, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of September 30, 2012, BGE could have been required to post approximately $51 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. As of September 30, 2012, Exelon's swaps were in an asset position, with a fair value of $30 million.

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

As of September 30, 2012 and December 31, 2011, $1 million of cash collateral posted and $2 million 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.

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

Commercial Paper Borrowings	September 30, 2012	December 31, 2011
Exelon Corporate	$ 15	$ 161
Generation	—	—
ComEd	35	—
PECO	—	—
BGE	—	—

Credit Facilities

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

Type of Credit Facility	Amount(a) (In billions)	Expiration Dates	Capacity Type
Exelon Corporate			
Syndicated Revolvers	$ 2.0	December 2012 and August 2017	Letters of credit and cash
Generation			
Syndicated Revolver	5.3	August 2017	Letters of credit and cash
Bilateral	0.3	December 2015 and March 2016	Letters of credit and cash
ComEd			
Syndicated Revolver	1.0	March 2017	Letters of credit and cash
PECO			
Syndicated Revolver	0.6	August 2017	Letters of credit and cash
BGE			
Syndicated Revolver	0.6	August 2017	Letters of credit and cash
Total	$ 9.8		

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

As of September 30, 2012, there were no borrowings under the Registrants' 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. Exelon Corporation (as successor to Constellation Energy Group) entered into an amendment to the Amended and Restated Credit Agreement dated March 12, 2012, which changed the maturity date to December 31, 2012. See Note 3 — Merger and Acquisitions for further description of the merger transaction.

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. Costs incurred to amend and extend the facilities for ComEd were not material.

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 fee varies depending upon ComEd's credit rating. The credit agreement also requires ComEd to pay a facility fee based upon the aggregate commitments under the agreement.

On August 10, 2012, Exelon Corporate, Generation, PECO and BGE amended and extended their respective unsecured syndicated revolving credit facilities, with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively, through August 10, 2017. Under these facilities Exelon Corporate, Generation, PECO and BGE may issue letters of credit in the aggregate of up to $200 million, $3.5 billion, $300 million and $600 million, respectively. Each credit facility permits the applicable borrower to request extensions for up to two additional one-year periods. Each credit facility also allows Exelon Corporate, Generation, PECO and BGE to request increases in aggregate commitments up to an additional $250 million, $1.0 billion, $250 million and $100 million, respectively. Any such extensions or increases are subject to the approval of the lenders party to the credit facilities in their sole discretion. Costs incurred to amend and extend the facilities for Exelon Corporate, Generation, PECO and BGE were not material.

The amended credit facilities updated the credit ratings-based pricing grids used to determine the facility fee and interest rates for borrowings under each facility and reflect current market pricing and maturities of five years from the close of the transactions. Borrowings under each credit agreement bear interest at a rate selected by the borrower based upon the prime rate or upon a LIBOR-based rate. Exelon Corporate, Generation, PECO and BGE have adders of 27.5, 7.5, 0.0 and 7.5 basis points for prime based borrowings and 127.5, 107.5, 100.0 and 107.5 basis points for LIBOR-based borrowings. The fee varies depending upon the respective credit ratings of each entity. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The covenants in each of Exelon Corporate, Generation, PECO and BGE's extended facilities are substantially consistent with existing covenants, with the exception of the BGE facility, in which a debt to capitalization financial covenant was replaced with an interest coverage ratio financial covenant.

On October 19, 2012, Generation, ComEd and PECO replaced their expiring minority and community bank credit facility agreements with new minority and community bank credit facility agreements in the amounts of $50 million, $34 million and $34 million, respectively, and BGE entered into a minority and community bank credit facility in the amount of $5 million. These facilities, which expire in October 2013, are solely utilized to issue letters of credit.

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 are being amortized to income over the life of the related debt as an increase to interest expense.

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

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

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, $258 million of which was outstanding as of September 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 September 30, 2012;
- $450 million aggregate principal amount of 8.625% Series A Junior Subordinated Debentures due 2063, all of which was outstanding as of September 30, 2012; and
- $550 million aggregate principal amount of 5.15% Notes due 2020, all of which was outstanding as of September 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 $212 million was outstanding as of September 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.

Generation filed a registration statement on Form S-4 on November 1, 2012 to register senior notes to be issued in connection with an exchange offer for the senior notes that were privately issued in June and July 2012. The registered notes will have the same terms and maturity dates as the privately placed senior notes.

Issuance of Long-Term Debt

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

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

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

On October 1, 2012, ComEd issued $350 million aggregate principal of its First Mortgage 3.80% Bonds, Series 113 due October 1, 2042. ComEd will use the net proceeds from the sale of the bonds to repay outstanding commercial paper obligations and for general corporate purposes.

During October 2012, Antelope Valley received DOE-guaranteed loan advances of $59 million at 2.482% and $2 million at 2.595%, due January 5, 2037.

During the nine months ended September 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.
ComEd	First Mortgage Bonds(a)	1.950%	September 1, 2016	$ 250	To be used to refinance the outstanding principal amount of three series of variable rate tax-exempt bonds, to refinance the outstanding principal of First Mortgage 5.40% Bonds due December 15, 2011.
ComEd	First Mortgage Bonds(a)	3.400%	September 1, 2021	$ 350	To be used to refinance the outstanding principal amount of three series of variable rate tax-exempt bonds, to refinance the outstanding principal of First Mortgage 5.40% Bonds due December 15, 2011.

(a) As of September 30, 2011, $536 million of the total proceeds from the issuances of First Mortgage Bonds due September 1, 2016 and September 1, 2021 was reflected in restricted cash on Exelon’s and ComEd’s Consolidated Balance Sheets for the purpose of redeeming outstanding debt under ComEd’s long-term debt refinancing authority with the ICC.

Retirement of Current and Long-Term Debt

During the nine months ended September 30, 2012, the following current and 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
Generation	CEU Credit Agreement	2.27%	June 16, 2016	$ 3
Generation	MEDCO Tax-Exempt Bonds	Variable	April 1, 2024	$ 75
Generation	Solar Revolver	2.49%	July 7, 2014	$ 13
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 2
Exelon	Senior Notes	7.60%	April 1, 2032	$ 442
Exelon	Medium Term Notes	7.30%	June 1, 2012	$ 2

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

On October 1, 2012, PECO retired $225 million aggregate principal of its 4.750% First and Refunding Mortgage Bonds due October 1, 2012.

On October 1, 2012, BGE retired $32 million aggregate principal of its 5.680% Rate Stabilization Bonds due April 1, 2017.

During the nine months ended September 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	$ 2
ComEd	Sinking fund debentures	4.75%	December 1, 2011	1

Accounts Receivable Agreement

PECO is party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its accounts receivable designated under the agreement in exchange for proceeds of $225 million, which is classified as a short-term note payable on Exelon's and PECO's Consolidated Balance Sheets. As of September 30, 2012 and December 31, 2011, the financial institution's undivided interest in Exelon's and PECO's gross accounts receivable was equivalent to $314 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. 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 August 31, 2012, PECO entered into an Amendment to extend this agreement until August 30, 2013. This Amendment also expands the criteria for eligible receivables to include receivables that have been purchased by PECO and revises the compliance criteria for the eligible asset test to allow for the payment of capital within a specified period of time. As of September 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. Antelope Valley received additional advances subsequent to the initial advance, and as of September 30, 2012, has received $100 million in DOE-guaranteed funding. See Note 8 — Derivative Financial Instruments for additional information on the interest rate swap related to the loan advances and Note 3 — Mergers and Acquisitions for additional information on the transaction.

In addition, Generation has issued letters of credit to support its equity investment in the project. As of September 30, 2012, Generation had $656 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.

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

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 September 30, 2012	Exelon(a)	Generation(a)	ComEd	PECO	BGE(b)
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	—%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	5.6	5.9	5.0	3.0	—
Qualified nuclear decommissioning trust fund income	7.8	21.5	—	—	—
Domestic production activities deduction	0.3	0.8	—	—	—
Tax exempt income	(0.2)	(0.5)	—	—	—
Health Care Reform Legislation	—	—	0.6	—	—
Amortization of investment tax credit, net deferred taxes	(4.8)	(13.0)	(0.5)	(0.3)	—
Plant basis differences	(4.7)	—	(0.5)	(21.0)	—
Production tax credits	(2.5)	(7.4)	—	—	—
Fines & penalties	(0.1)	—	—	—	—
Other(d)	(1.2)	7.1	—	0.2	—
Effective income tax rate	35.2%	49.4%	39.6%	16.9%	—%

For the Nine Months Ended September 30, 2012	Exelon(a)	Generation(a)	ComEd	PECO	BGE(b)
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	(4.7)	2.5	5.4	3.2	2.3
Qualified nuclear decommissioning trust fund income	6.9	10.9	—	—	—
Tax exempt income	(0.3)	(0.5)	—	—	—
Health Care Reform Legislation	0.2	—	0.6	—	(4.6)
Amortization of investment tax credit, net deferred taxes	(2.3)	(3.3)	(0.5)	(0.3)	2.9
Plant basis differences	(2.2)	—	(0.2)	(9.7)	7.2
Production tax credits	(2.6)	(4.3)	—	—	—
Fines & penalties	3.8	6.0	—	—	—
Merger expenses(c)	3.6	—	—	—	(14.0)
Other	(1.3)	0.8	0.2	(0.0)	4.5
Effective income tax rate	36.1%	47.1%	40.5%	28.2%	33.3%

For the Three Months Ended September 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	4.8	5.5	0.8	2.9	6.2
Qualified nuclear decommissioning trust fund income	(6.4)	(10.2)	—	—	—
Domestic production activities deduction	1.0	1.7	—	—	—
Tax exempt income	(0.1)	(0.2)	—	—	—
Health Care Reform Legislation	—	—	0.3	—	(16.4)
Amortization of investment tax credit	(0.3)	(0.2)	(0.5)	(0.3)	13.8
Plant basis differences	(3.2)	—	(0.7)	(23.8)	48.4
Production tax credits	(1.1)	(1.7)	—	—	—
Interest and penalties on unrecognized tax benefits(e)	—	—	—	—	137.8
Other	0.1	0.3	0.4	0.1	75.2
Effective income tax rate	29.8%	30.2%	35.3%	13.9%	300.0%

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

For the Nine Months Ended September 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	4.1	4.9	3.4	(0.4)	4.8
Qualified nuclear decommissioning trust fund income	(0.6)	(0.8)	—	—	—
Domestic production activities deduction	(0.4)	(0.6)	—	—	—
Tax exempt income	(0.1)	(0.2)	—	—	—
Health Care Reform Legislation	—	—	(1.5)	—	(0.8)
Amortization of investment tax credit	(0.3)	(0.2)	(0.4)	(0.3)	(0.5)
Plant basis differences	(1.0)	—	(0.4)	(6.8)	(1.6)
Production tax credits	(1.0)	(1.4)	—	—	—
Interest and penalties on unrecognized tax benefits(e)	—	—	—	—	(1.1)
Other	(0.3)	(0.9)	0.3	—	(0.1)
Effective income tax rate	35.4%	35.8%	36.4%	27.5%	35.7%

(a) Exelon activity for the three and nine months ended September 30, 2012 includes the results of Constellation and BGE for March 12, 2012 — September 30, 2012. Generation activity for the three and nine months ended September 30, 2012 includes the results of Constellation for March 12, 2012 — September 30, 2012.

(b) BGE activity represents the activity for the three and nine months ended September 30, 2012 and 2011. BGE activity for the three months ended September 30, 2012 resulted in zero pre-tax income and zero income taxes. BGE recognized a loss before income taxes for the nine months ended September 30, 2012 and three months ended September 30, 2011. As a result, positive percentages represent an income tax benefit for BGE for the nine months ended September 30, 2012 and three months ended September 30, 2011.

(c) Prior to the close of the merger, the Registrants recorded the applicable taxes on merger transaction costs assuming the merger would not be completed. Upon closing of the merger, the Registrants reversed such taxes for those merger transaction costs that were determined to be non tax-deductible upon successful completion of a merger.

(d) For the three months ended September 31, 2012, Generation's effective tax rate was affected by the resolution of uncertain Federal tax positions (5.3%), the finalization of prior year tax return calculations 4.2%, changes in the forecasted activity attributable to noncontrolling interests 4.1%, and other 4.1%.

(e) Until March 12, 2012, BGE recorded interest and penalties relating to unrecognized tax benefits as tax expense.

Accounting for Uncertainty in Income Taxes

Exelon, Generation, ComEd, PECO, and BGE have $980 million, $829 million, $68 million, $44 million, and $0 million, respectively, of unrecognized tax benefits as of September 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. Exelon has received verbal confirmation from the IRS that the Joint Committee on Taxation has approved the terms of the preliminary agreement and Exelon expects final IRS approval in the fourth quarter of 2012.

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 September 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 $870 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 September 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).

In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The change to the newly adopted method for the 2011 tax year and through Q3 2012 resulted in a tax benefit of $19 million at Exelon, of which $22 million in tax benefit is recorded at PECO, partially offset by an expense recorded at Generation to reflect a reduction in its domestic production activities deduction. BGE changed its method of accounting for gas distribution repairs for the 2008 tax year. Exelon currently anticipates that the IRS will issue guidance in the near future providing a safe harbor method of tax accounting for gas transmission and distribution property.

Interest Expense on Income Taxes (BGE)

For the three and nine months ended September 30, 2012, BGE recorded an adjustment to interest expense of approximately $2 million and $9 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 nine months ended September 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. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

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

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

Nuclear decommissioning ARO at December 31, 2011(a)	$3,680
Accretion expense	169
Net increase due to changes in estimated cash flows	749
Costs incurred to decommission retired plants	(2)
Nuclear decommissioning ARO at September 30, 2012(a)	$4,596

(a) Includes $6 million and $5 million as the current portion of the ARO at September 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 nine months ended September 30, 2012, Generation's ARO increased by $916 million. The increase in the ARO is largely driven by four factors: i) changes in the timing of the future nominal cash flows resulting from an assumed five year deferral to 2025 of the acceptance date of spent nuclear fuel by the DOE coupled with the fact that; ii) cash flows affected by this change in timing are re-measured and discounted at current CARFRs, which have dramatically decreased given the current low interest rate environment; iii) an increase in the estimated costs to decommission the Quad Cities and Dresden nuclear units resulting from the completion of updated decommissioning costs studies received during 2012; and iv) accretion of the obligation. The increase in the ARO due to the changes in estimated cash flows resulted in $10 million of expense, which is included in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

During the third quarter of 2011, Generation recorded a net increase in the ARO of $176 million primarily due to an increase in the estimated costs to decommission the Oyster Creek and Zion nuclear units resulting from the completion of updated decommissioning cost studies received in 2011 and an increase in the expected long-term escalation rates for energy, partially offset by decreases in long-term escalation rates for labor and other costs as compared to prior study periods. The increase in the Zion nuclear unit ARO resulted in $28 million of expense, which is included in Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income, as the Zion nuclear unit is retired, and as such, is unable to record increases to the ARO through an ARC. Additionally, the Zion nuclear unit is not subject to a regulatory agreement that would provide for offset of the expense.

Nuclear Decommissioning Trust Fund Investments

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

The NDT funds associated with the former ComEd, former PECO and former AmerGen units have been funded with amounts collected from ComEd customers, PECO customers and the previous owners of the former AmerGen plants, respectively. Based on an ICC order, ComEd ceased collecting amounts from its customers to pay for decommissioning costs. PECO currently collects funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections 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.

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

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 September 30, 2012 and December 31, 2011, Exelon and Generation had NDT fund investments totaling $7,140 million and $6,507 million, respectively. The following table provides unrealized gains (losses) on NDT funds for the three and nine months ended September 30, 2012 and 2011:

	Exelon and Generation			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net unrealized gains (losses) on decommissioning trust funds — Regulatory Agreement Units(a)	$ 202	$ (363)	$ 352	$ (223)
Net unrealized gains (losses) on decommissioning trust funds — Non-Regulatory Agreement Units(b)(c)	71	(141)	101	(88)

(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 $22 million of net unrealized gains and $4 million of net unrealized losses related to the Zion Station pledged assets for the three months ended September 30, 2012 and 2011, respectively, and $60 million and $41 million of net unrealized gains related to the Zion Station pledged assets for the nine months ended September 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 $78 million, which is included within the nuclear decommissioning ARO at September 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 September 30, 2012, the carrying value of the Zion Station pledged assets and the payable to Zion Solutions was approximately $631 million and $582 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 September 30, 2012 and December 31, 2011 was $160 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. The curtailment and associated remeasurement resulted in an increase and a decrease to the pension and other postretirement benefit obligations 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.

During the third quarter of 2012, Exelon announced plan design changes for certain other postretirement benefit plans, requiring an interim remeasurement of the benefit obligation and assets for those plans using assumptions as of September 30, 2012, including updated discount rates and asset values. The discount rates used to calculate the other postretirement benefit plan obligations for legacy Exelon and Constellation were 3.93% and 3.72%, respectively, as of September 30, 2012. The remeasurement resulted in an increase to the other postretirement benefit obligation, accumulated other comprehensive loss, and regulatory assets of $212 million, $68 million (after-tax), and $99 million, respectively. Additionally, Exelon recognized a $5 million curtailment gain in the third quarter of 2012 related to these plan design changes, of which Generation and BGE recognized a curtailment gain of $1 million and $3 million, respectively.

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

The following tables present the components of Exelon's net periodic benefit costs for the three and nine months ended September 30, 2012 and 2011. The 2012 pension benefit cost for legacy Exelon plans was calculated using an expected long-term rate of return on plan assets of 7.50% and a discount rate of 4.74%. The 2012 pension benefit cost for legacy Constellation plans was calculated using an expected long-term rate of return on plan assets of 7.50% and discount rates of 4.27% and 3.97% for the period post-merger through June 30, 2012 and July 1, 2012 through September 30, 2012, respectively. The 2012 other postretirement benefit cost for legacy Exelon plans was calculated using an expected long-term rate of return on plan assets of 6.68% and a discount rate of 4.80%. The 2012 other postretirement benefit cost for legacy Constellation plans was calculated using a discount rate of 4.28% and 3.98% for the period post-merger through June 30, 2012 and July 1, 2012 through September 30, 2012, respectively. Legacy Constellation other postretirement benefit plans are not funded. A portion of the net periodic benefit cost is capitalized within the Consolidated Balance Sheets.

	Pension Benefits Three Months Ended September 30,		Other Postretirement Benefits Three Months Ended September 30,	
	2012	2011	2012	2011
Service cost	$ 76	$ 53	$ 38	$ 36
Interest cost	181	162	53	52
Expected return on assets	(258)	(235)	(28)	(27)
Amortization of:				
Transition obligation	—	—	2	2
Prior service cost (benefit)	5	4	(3)	(10)
Actuarial loss	117	83	19	16
Settlement Charges	9	—	—	—
Curtailment gain	—	—	(5)	—
Net periodic benefit cost	$ 130	$ 67	$ 76	$ 69

	Pension Benefits Nine Months Ended September 30,		Other Postretirement Benefits Nine Months Ended September 30,	
	2012	2011	2012	2011
Service cost	$ 211	$ 159	$ 114	$ 107
Interest cost	524	487	157	155
Expected return on assets	(742)	(704)	(86)	(83)
Amortization of:				
Transition obligation	—	—	8	7
Prior service cost (benefit)	12	11	(10)	(29)
Actuarial loss	338	248	58	49
Settlement Charges	9	—	—	—
Contractual termination benefit cost(a)	14	—	6	—
Curtailment gain	—	—	(7)	—
Net periodic benefit cost	$ 366	$ 201	$ 240	$ 206

(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 nine months ended September 30, 2012 and 2011, for Generation's, ComEd's, PECO's, BGE's and BSC's allocated portion of the pension and postretirement benefit plan costs. These amounts include the recognized contractual termination benefit charges, curtailment gains, and settlement charges.

Pension and Postretirement Benefit Costs	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Generation	$ 85	$ 64	$ 259	$ 187
ComEd	75	53	212	160
PECO	12	8	38	24
BGE(a)(b)	14	15	46	43
BSC(c)	20	11	63	36

(a) BGE's pension and postretirement benefit costs for the nine months ended September 30, 2012 include $12 million of costs incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012. BGE's pension and postretirement benefit costs for the three months and nine months ended September 30, 2011 were $15 million and $43 million, respectively. These amounts are not included in Exelon's net periodic benefit costs for the three and nine months ended September 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 nine months ended September 30, 2012 includes a $3 million contractual termination benefit charge, which was recorded as a regulatory asset as of September 30, 2012.

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

During the fourth quarter of 2012, Exelon will record an additional settlement charge of approximately $17 million. This charge is triggered by lump sum payments made to executives during the fourth quarter of 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 $77 million to its qualified pension plans in 2012, of which Generation, ComEd, and PECO will contribute $46 million, $9 million, and $13 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 $131 million, $116 million, $33 million, and $13 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 nine months ended September 30, 2012 and 2011:

Savings Plan Matching Contributions	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Exelon	$ 16	$ 26	$ 49	$ 64
Generation	7	13	23	33
ComEd	5	8	14	18
PECO	2	3	5	7
BGE(a)	1	1	5	5
BSC(b)	1	2	3	6

(a) BGE's matching contributions for the nine months ended September 30, 2012 include $1 million of costs incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012, which is not included in Exelon's matching contributions for the nine months ended September 30, 2012.
(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO or BGE amounts above.

13. Plant Retirements (Exelon and Generation)

Schuylkill Station and Riverside Station

On October 31, 2012, Generation notified PJM of its intention to permanently retire Schuylkill Generating Station Unit 1 by February 1, 2013, and Riverside Generating Station Unit 6 by June 1, 2014. Schuylkill Unit 1 is a 166 MW peaking oil unit located in Philadelphia, Pennsylvania, which was placed in service in 1958. Riverside Unit 6 is a 115 MW peaking gas/kerosene unit located in Baltimore, Maryland, which was placed in service in 1970. The units are being retired because they are no longer economic to operate due to their age, relatively high capital and operating costs and declining revenue expectations. PJM has 30 days to review whether the proposed retirements of the units create transmission system reliability issues. Once PJM's review is complete, Exelon will determine final retirement dates for the units. The impact of the early retirements will not have a material impact on Generation or Exelon's results of operations, cash flows or financial position.

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

Eddystone Station and Cromby Station

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.

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

Severance Benefits Obligation	Exelon and Generation
Balance at December 31, 2011	$ 7
Cash payments	(2)
Balance at September 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 September 30, 2012, there were approximately 20 million shares authorized for issuance under the LTIP. For the three and nine months ended September 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.

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

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.

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

Components of Stock-Based Compensation Expense	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Performance share awards	$ 5	$ 6	$ 32	$ 17
Stock options	2	1	13	7
Restricted stock units	12	5	41	26
Other stock-based awards	1	1	3	3
Total stock-based compensation expense included in operating and maintenance expense	20	13	89	53
Income tax benefit	(8)	(5)	(34)	(21)
Total after-tax stock-based compensation expense	$ 12	$ 8	$ 55	$ 32

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

Subsidiaries	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Generation	$ 9	$ 6	$ 33	$ 24
ComEd	2	1	9	4
PECO	1	1	4	4
BGE(a)	1	—	4	—
BSC(b)	7	5	39	21
Total	$ 20	$ 13	$ 89	$ 53

(a) BGE's stock-based compensation expense for the nine months ended September 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 nine months ended September 30, 2012 shown in the table titled Components of Stock-Based Compensation Expense above. BGE's stock-based compensation expense for the three and nine months ended September 30, 2011 was $1 million and $5 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 nine months ended September 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 nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 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 nine months ended September 30, 2012.

The following table summarizes Exelon's stock option activity for the nine months ended September 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	(1,575,275)	26.57
Forfeited	(28,142)	44.88
Expired	(488,434)	48.59
Balance of shares outstanding at September 30, 2012	23,028,061	$ 45.61
Exercisable at September 30, 2012(a)	20,962,469	$ 46.08

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

The following table summarizes Exelon's nonvested stock option activity for the nine months ended September 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)	(11,889,175)	41.39
Forfeited	(488,434)	48.59
Nonvested at September 30, 2012(a)	2,065,592	$ 40.60

(a) Excludes 2,719,671 and 1,348,000 of stock options issued to retirement-eligible employees as of September 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 1,667,000 of stock options issued to retirement-eligible employees in 2012 that vested immediately upon the employee reaching retirement eligibility.

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

At September 30, 2012, $8 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of 2.5 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 nine months ended September 30, 2012:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2011(a)	1,074,484	$ 48.08
Granted	1,283,292	39.93
Converted Constellation restricted stock	825,735	38.91
Vested	(427,499)	47.69
Forfeited	(47,415)	42.67
Undistributed vested awards(b)	(602,276)	40.53
Nonvested at September 30, 2012(a)	2,106,321	$ 42.27

(a) Excludes 656,228 and 448,827 of restricted stock units issued to retirement-eligible employees as of September 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 September 30, 2012, Exelon had obligations related to outstanding restricted stock units not yet settled of $58 million, which are included in common stock in Exelon's Consolidated Balance Sheets. As of September 30, 2012, Exelon had no obligations related to outstanding restricted stock units that will be settled in cash. During the three months ended September 30, 2012 and 2011, Exelon settled restricted stock units with a fair value totaling $4 million and $1 million, respectively. During the nine months ended September 30, 2012 and 2011, Exelon settled restricted stock units with a fair value totaling $23 million and $19 million, respectively. At September 30, 2012, $54 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.08 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

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

portion is considered an equity award with the 75% payout floor being valued based on Exelon's stock price on the grant date. The cash portion of the award is considered a liability award with the 75% payout floor being remeasured each reporting period based on Exelon's current stock price. The expected payout in excess of the 75% floor for the equity and liability portions are remeasured each reporting period based on Exelon's current stock price and changes in the expected payout of the award; therefore these portions of the award are subject to volatility until the payout is established.

For nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method. For performance 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 nine months ended September 30, 2012:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2011(a)	346,848	$ 45.37
Granted	1,249,932	39.73
Vested	(159,194)	47.66
Forfeited	(113,761)	39.79
Undistributed vested awards(b)	(128,370)	40.98
Nonvested at September 30, 2012(a)	1,195,455	$ 40.17

(a) Excludes 204,643 and 455,418 of performance share awards issued to retirement-eligible employees as of September 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 September 30, 2012 and 2011, the fair value of Exelon's settled performance shares and payments made in cash were immaterial. During the nine months ended September 30, 2012 and 2011, Exelon settled performance shares with a fair value totaling $22 million and $21 million, respectively, of which $3 million and $10 million was paid in cash, respectively. As of September 30, 2012, $19 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 2.3 years.

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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net income on common stock	$ 296	$ 601	$ 782	$ 1,889
Average common shares outstanding — basic	854	663	804	663
Assumed exercise of stock options, performance share awards and restricted stock	3	2	2	1
Average common shares outstanding — diluted	857	665	806	664

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 18 million and 13 million for the three and nine months ended September 30, 2012, respectively, and 10 million and 9 million for the three and nine months ended September 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 September 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 September 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	$ 111	$ 8	$ 8	$ 148	$ 275
2013	375	92	32	699	1,198
2014	352	62	26	451	891
2015	350	23	13	—	386
2016	266	9	2	—	277
Thereafter	672	8	36	—	716
Total	$ 2,126	$ 202	$ 117	$ 1,298	$3,743

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(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 September 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 agreements with CENG were modified to be unit-contingent through the end of their original term in 2014. Under these agreements, CENG has the ability to fix the energy price on a forward basis by entering into monthly energy hedge transactions for a portion of the future sale, while any unhedged portions will be provided at market prices by default. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, Generation agreed to purchase 50.01% of the available output of CENG's nuclear plants at market prices. Generation discloses in the table commitments to purchase from CENG at fixed prices. All commitments to purchase at market prices, which include all purchases subsequent to December 31, 2014, are excluded from the table. Generation continues to own a 50.01% membership interest in CENG that is accounted for as an equity method investment. See Note 55 — Investment in Constellation energy Nuclear Group, LLC for more details on this arrangement.

ComEd's, PECO's and BGE's electric supply procurement, curtailment services, REC and AEC purchase commitments as of September 30, 2012 are as follows:

		Expiration within					
	Total	2012	2013	2014	2015	2016	2017 and beyond
ComEd							
Electric supply procurement(a)	$1,103	$ —	$367	$323	$136	$137	$ 140
Renewable energy and RECs(b)	1,694	33	71	73	74	76	1,367
PECO							
Electric supply procurement(c)	789	210	413	130	36	—	—
AECs	35	3	11	9	2	2	8
Curtailment services	4	4	—	—	—	—	—
BGE							
Electric supply procurement(d)	1,171	201	707	263	—	—	—
Curtailment services	165	11	49	47	41	17	—

(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.

(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 September 30, 2012, these net commitments were as follows:

		Expiration within					
	Total	2012	2013	2014	2015	2016	2017 and beyond
Generation	$8,668	$263	$1,252	$1,298	$1,279	$929	$ 3,647
PECO	412	55	114	68	53	31	91
BGE	657	44	125	72	52	51	313

Other Purchase Obligations

The Registrants' other purchase obligations as of September 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	$1,049	$434	$217	$135	$94	$32	$ 137
Generation	555	248	110	91	69	8	29
ComEd	115	41	34	6	5	5	24
PECO	109	61	21	17	1	1	8
BGE	19	17	2	—	—	—	—

Construction Commitments

Generation has committed to the construction of a solar PV facility in Los Angeles County, California. Generation's estimated commitments are $192 million and $650 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, approximately 272MW of which is still under construction as of September 30, 2012. Generation's estimated commitments for the wind turbines are approximately $100 million for the remainder of 2012, 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.

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

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.

Contingencies

Commercial Commitments

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

	Exelon	Generation	ComEd	PECO	BGE
Letters of credit (non-debt)(a)	$ 2,290	$ 2,082	$ 142	$ 22	$ 1
Guarantees	10,406(b)	2,355(c)	208(d)	181(e)	250(f)
Nuclear insurance premiums(g)	2,098	2,098	—	—	—
Total commercial commitments	$14,794	$ 6,535	$ 350	$203	$251

(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 $1.5 billion at September 30, 2012, which represents the total amount Exelon could be required to fund based on September 30, 2012 market prices.
(c) Primarily reflects guarantees issued to ensure performance under energy marketing and other specific contracts and $211 million on behalf of CENG nuclear generating facilities for credit support. The estimated net exposure for obligations under commercial transactions covered by these guarantees was $0.5 billion at September 30, 2012, which represents the total amount Generation could be required to fund based on September 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 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 is $2.1 billion which is included above in the Commercial Commitments table and which does not include the potential

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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 September 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 September 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 in 2013. The guarantee of $95 million is included above in the Commercial Commitments table under Guarantees.

Environmental Issues

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

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

- ComEd has identified 42 sites, 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.

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

- PECO has identified 26 sites, 16 of which have been approved for cleanup by the PA DEP and 10 that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2019.
- BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor's acquisition. Two sites require some level of remediation under the direction of the MDE. The required remediation cost at these two sites is not considered material. One additional site is in the initial stages of investigation at the direction of the MDE.

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 and third quarter of 2012, ComEd and PECO, respectively, completed an annual study of their future estimated MGP remediation requirements. The results of these studies indicated that additional remediation would be required at certain sites; accordingly, ComEd and PECO increased their reserves and regulatory assets by $146 million and $7 million, respectively. 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 $111 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 September 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:

September 30, 2012	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 351	$ 307
Generation	35	—
ComEd	265	260
PECO	50	47
BGE	1	—

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
BGE	—	—

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 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 September 30, 2012, approximately $18 million of these costs had been paid, resulting in a remaining liability at September 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 following a public comment period. 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 September 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. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA had exceeded its authority in certain material aspects of CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. On October 5, 2012, the DOJ, on behalf of the U.S. EPA, filed a petition for a re-hearing *en banc* (i.e., before all the D.C. Circuit Court judges) of the panel's decision. On the same date Exelon joined with other industry members in a petition for an *en banc* review.

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. A decision by the Court is not expected until some time in 2013.

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 September 30, 2012, Exelon had a $678 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 — 2014 timeframe for particulate matter, nitrogen dioxide, sulfur dioxide, ozone, 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 CAIR (and in the future 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 2014. Litigation of the ozone standard in the D.C. Circuit Court continues with an oral argument scheduled for November 2012. 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 indicated in its proposals 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 MATS regulation. It is unclear if the vacatur of the CSAPR, one of the regulations that the U.S. EPA is relying on to assist with future PM reduction, would alter the U.S. EPA's view since either CAIR or a finalized CSAPR regulation would be in effect leading up to 2020.

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. In addition, on November 1, 2012, EI stated that there is no assurance that interest payments due on the unsecured debt would

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be paid as required on November 15, 2012, and that failure to pay will likely result in EME's filing for protection under Chapter 11 of the U.S. Bankruptcy code. In that event, ComEd and Generation would be unsecured creditors 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 $90 million. The DOJ and the PRPs have agreed to toll the statute of limitations until August 2013 so that settlement discussions can proceed. Based on Exelon's preliminary review, it appears probable that Exelon has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability.

On February 28, 2012, and April 12, 2012, two lawsuits were filed in the U.S. District Court for the Eastern District of Missouri against 15 and 14 defendants, respectively, including Exelon, Generation and ComEd (the "Exelon defendants"). 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.

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

68th Street Dump. In 1999, the U.S. EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In March 2004, BGE and other PRPs formed the 68th Street Coalition and entered into consent order negotiations with the U.S. EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the U.S. EPA and 19 of the PRPs, including BGE, with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The potentially responsible parties submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the U.S. EPA are still subject to U.S. EPA review and selection of a remedy, the range of estimated clean-up costs to be allocated among all of the PRPs is in the range of $50 million to $64 million. The U.S. EPA is expected to make a final selection of one of the alternatives in 2012. Based on Exelon's preliminary review, it appears probable that Exelon has liability and has established an appropriate accrual for its share of the estimated clean-up costs. BGE is indemnified by a wholly owned subsidiary of Generation for most of the costs related to this settlement and clean-up of the site.

Sauer Dump. On May 30, 2012, BGE was notified by the U.S. EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, MD. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. 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 July 2, 2012 the U.S. EPA declined to lower GHG permit
thresholds in its final "Step 3" Tailoring Rule update. The U.S. EPA will review permit thresholds again in a 2015 rulemaking process. On June 26, 2012, the United States Court of Appeals for the District of Columbia, in a *per 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. In August 2012, several industry parties filed petitions for an *en banc* rehearing of the Agency's GHG regulations with the D.C. Circuit Court. On September 6, 2012 the Circuit Court ordered the U.S. EPA, intervening environmental groups, and some states to reply to the industry petitions.

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.

At September 30, 2012 and December 31, 2011, Generation had reserved approximately $64 million and $49 million, respectively, in total for asbestos-related bodily injury claims. As of September 30, 2012, approximately $14 million of this amount related to 170 open claims presented to Generation, while the remaining $50 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary. During the second quarter of 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; as such, no accrual has been made. 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 $16 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 nine months ended September 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 September 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 was concluded in September 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.

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.

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

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 nine months ended September 30, 2012 and 2011:

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

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

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

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Three Months Ended September 30, 2011	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory Agreement Units	$ 16	$ 16	$ —	$ —	$ —
Non-Regulatory Agreement Units	13	13	—	—	—
Net unrealized losses on decommissioning trust funds					
Regulatory Agreement Units	(363)	(363)	—	—	—
Non-Regulatory Agreement Units	(141)	(141)	—	—	—
Net unrealized losses on pledged assets					
Zion Station decommissioning	(4)	(4)	—	—	—
Regulatory offset to decommissioning trust fund-related activities(b)	281	281	—	—	—
Total decommissioning-related activities	(198)	(198)	—	—	—
Investment income	1	—	—	1	3
Long-term lease income	7	—	—	—	—
Interest income related to uncertain income tax positions	7	—	12	—	—
AFUDC — Equity	4	—	2	2	4
Bargain purchase gain related to Wolf Hollow acquisition	36	36	—	—	—
Other	1	(2)	2	—	1
Other, net	$(142)	$ (164)	$ 16	$ 3	$ 8

Nine Months Ended September 30, 2011	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory Agreement Units	$ 97	$ 97	$ —	$ —	$ —
Non-Regulatory Agreement Units	39	39	—	—	—
Net unrealized losses on decommissioning trust funds					
Regulatory Agreement Units	(223)	(223)	—	—	—
Non-Regulatory Agreement Units	(88)	(88)	—	—	—
Net unrealized income on pledged assets					
Zion Station decommissioning	41	41	—	—	—
Regulatory offset to decommissioning trust fund-related activities(b)	60	60	—	—	—
Total decommissioning-related activities	(74)	(74)	—	—	—
Investment income	3	—	—	3	10
Long-term lease income	21	—	—	—	—
Interest income related to uncertain income tax positions	53	33	13	1	—
AFUDC — Equity	14	—	6	8	11
Bargain purchase gain related to Wolf Hollow acquisition	36	36	—	—	—
Other	1	(7)	5	(1)	1
Other, net	$ 54	$ (12)	$ 24	$ 11	$ 22

(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.

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

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the nine months ended September 30, 2012 and 2011:

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

Nine Months Ended September 30, 2011	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization and accretion					
Property, plant and equipment	$ 947	$ 416	$ 374	$141	$170
Regulatory assets	40	—	31	9	35
Nuclear fuel(a)	556	556	—	—	—
Asset retirement obligation accretion(b)	159	159	—	—	—
Total depreciation, amortization and accretion	$1,702	$ 1,131	$ 405	$150	$205

(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.

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

Nine Months Ended September 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 606	$ 259	$ 212	$ 38	$ 44
Provision for uncollectible accounts	120	14	38	46	28
Stock-based compensation costs	75	—	—	—	—
Other decommissioning-related activity(a)	(108)	(108)	—	—	—
Energy-related options(b)	119	119	—	—	—
Amortization of regulatory asset related to debt costs	13	—	10	2	1
Amortization of rate stabilization deferral	39	—	—	—	49
Amortization of debt fair value adjustment	(49)	(23)	—	—	—
Discrete impacts from EIMA(c)	43	—	43	—	—
Merger-related commitments(d)	179	35	—	—	28
Severance cost	120	34	—	1	—
Equity in losses of unconsolidated subsidiaries	69	69	—	—	—
Other	9	23	7	9	(3)
Total other non-cash operating activities	$1,235	$ 422	$ 310	$ 96	$147
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	20	—	21	(3)	21
Other regulatory assets and liabilities	(463)	—	(65)	7	(89)
Other current assets	52	(85)	(8)	(56)(e)	(25)
Other noncurrent assets and liabilities	(40)	(110)	(72)	(5)	7
Total changes in other assets and liabilities	$ (431)	$ (195)	$ (124)	$ (57)	$ (86)
Non-cash investing and financing activities:					
Merger with Constellation, common stock issued	$7,365	$ 5,258	$ —	$ —	$ —
Total non-cash investing and financing activities:	$7,365	$ 5,258	$ —	$ —	$ —

Nine Months Ended September 30, 2011	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 407	$ 187	$ 160	$ 24	$ 43
Provision for uncollectible accounts	97	—	49	48	31
Stock-based compensation costs	55	—	—	—	—
Other decommissioning-related activity(a)	62	62	—	—	—
Energy-related options(b)	102	102	—	—	—
Amortization of regulatory asset related to debt costs	16	—	14	2	1
Amortization of rate stabilization deferral	—	—	—	—	45
Deferral of storm costs	—	—	—	—	(16)
Uncollectible accounts recovery, net	14	—	14	—	—
Discrete impacts from 2010 Rate Case Order(f)	(32)	—	(32)	—	—
Bargain purchase gain related to Wolf Hollow Acquisition	(36)	(36)	—	—	—
Other	18	47	5	—	(6)
Total other non-cash operating activities	$ 703	$ 362	$ 210	$ 74	$ 98
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	(9)	—	(20)	11	(25)
Other regulatory assets and liabilities	—	—	12	13	13
Other current assets	(166)	(46)	(13)	(59)(e)	(92)
Other noncurrent assets and liabilities	83	(19)	50	7	(50)
Total changes in other assets and liabilities	$ (92)	$ (65)	$ 29	$ (28)	$(154)

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

(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, which represents the ICC's approved distribution formula and associated rulings as of September 30, 2012 and ComEd's best estimate of the probable increase in distribution rates to provide recovery of prudent and reasonable costs incurred for the twelve months ended December 31, 2011 and the nine months ended September 30, 2012. 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 nine months ended September 30, 2012, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $75 million, $45 million and $30 million, respectively, and reimbursements of $85 million, $55 million and $30 million, respectively, related to PECO's and BGE's DOE SGIG programs. For the nine months ended September 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 $47 million, $29 million and $18 million, respectively, and reimbursements of $86 million, $45 million and $41 million, respectively, related to PECO's and BGE's DOE SGIG programs. See Note 4 — Regulatory Matters for additional information regarding the DOE SGIG.

Supplemental Balance Sheet Information

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

September 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$11,890(a)	$ 5,910(a)	$2,906	$2,765	$2,579
Accounts receivable:					
Allowance for uncollectible accounts	310	85	81	109	35

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 $2,161 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 September 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 September 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 September 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 September 30, 2012 and December 31, 2011:

September 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Accumulated other comprehensive income (loss)					
Net unrealized gain on cash flow hedges	$ 459	$ 730	$ —	$ —	$—
Pension and non-pension postretirement benefit plans	(2,887)	—	—	—	—
Other comprehensive income — equity investment in CENG	23	23	—	—	—
Unrealized gain (loss) on marketable securities	—	(1)	—	1	—
Total accumulated other comprehensive income (loss)	$(2,405)	$ 752	$ —	$ 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.
- 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)

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the three and nine months ended September 30, 2012 and 2011 is as follows:

Three Months Ended September 30, 2012 and 2011

	Generation(a)	ComEd	PECO	BGE	Other(b)	Intersegment Eliminations	Exelon
Total revenues(c):							
2012	$ 4,017	$ 1,484	$ 806	$ 720	$ 336	$ (798)	$ 6,565
2011	2,821	1,784	946	—	206	(503)	5,254
Intersegment revenues(d):							
2012	$ 459	$ —	$ 1	$ 4	$ 334	$ (798)	$ —
2011	304	1	2	—	203	(503)	7
Net income (loss):							
2012	$ 87	$ 90	$ 123	$ —	$ (3)	$ —	$ 297
2011	386	112	105	—	(1)	—	602
Total assets:							
September 30, 2012	$ 41,090	$22,471	$9,661	$7,504	$10,150	$ (12,523)	$78,353
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 September 30, 2012 include revenue from sales to PECO of $ 171 million and sales to BGE of $120 million in the Mid-Atlantic region, and sales to ComEd of $180 million in the Midwest region, net of $ (15) million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation. For the three months ended September 30, 2011 intersegment revenues for Generation include revenue from sales to PECO of $137 million in the Mid-Atlantic region, and sales to ComEd of $159 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 September 30, 2012 and 2011, utility taxes of $28 million and $7 million, respectively, are included in revenues and expenses for Generation. For the three months ended September 30, 2012 and 2011, utility taxes of $67 million and $64 million, respectively, are included in revenues and expenses for ComEd. For the three months ended September 30, 2012 and 2011, utility taxes of $40 million and $50 million, respectively, are included in revenues and expenses for PECO. For the three months ended September 30, 2012, utility taxes of $20 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.

(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	$ 1,428	$ (11)	$ 1,417	$ 1,032	$ —	$ 1,032
Midwest	1,193	7	1,200	1,385	—	1,385
New England	390	1	391	2	—	2
New York	183	2	185	—	—	—
ERCOT	532	1	533	307	—	307
Other Regions(b)	317	12	329	77	—	77
Total Revenues for Reportable Segments	$ 4,043	$ 12	$ 4,055	$ 2,803	$ —	$ 2,803
Other(c)	(35)	(3)	(38)	18	—	18
Total Generation Consolidated Operating Revenues	$ 4,008	$ 9	$ 4,017	$ 2,821	$ —	$ 2,821

(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	$ 919	$ (11)	$ 908	$ 835	$ —	$ 835
Midwest	723	7	730	852	—	852
New England	80	1	81	1	—	1
New York	11	2	13	—	—	—
ERCOT	158	—	158	103	—	103
Other Regions(b)	30	12	42	(4)	—	(4)
Total Revenues net of purchased power and fuel expense for Reportable Segments	$ 1,921	$ 11	$1,932	$ 1,787	$ —	$1,787
Other(c)	(26)	(11)	(37)	(37)	—	(37)
Total Generation Revenues net of purchased power and fuel expense	$ 1,895	$ —	$1,895	$ 1,750	$ —	$1,750

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

Nine Months Ended September 30, 2012 and 2011

	Generation(a)	ComEd	PECO	BGE(b)	Other(c)	Intersegment Eliminations	Exelon
Total revenues(d):							
2012	$ 10,509	$4,154	$2,396	$1,388	$1,049	$ (2,291)	$17,205
2011	7,919	4,694	2,942	—	579	(1,429)	14,705
Intersegment revenues(e):							
2012	$ 1,233	$ 2	$ 3	$ 7	$1,050	$ (2,291)	$ 4
2011	856	2	4	—	576	(1,429)	9
Net income (loss):							
2012	$ 419	$ 219	$ 300	$ (50)	$ (101)	$ —	$ 787
2011	1,325	295	314	—	(45)	—	1,889

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. Intersegment revenues for Generation for the nine months ended September 30, 2012 include revenue from sales to PECO of $407 million and sales to BGE of $223 million in the Mid-Atlantic region, and sales to ComEd of $631 million in the Midwest region, net of $ (30) million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation. For the nine months ended September 30, 2011 intersegment revenues for Generation include revenue from sales to PECO of $394 million in the Mid-Atlantic region, and sales to ComEd of $450 million in the Midwest region.
(b) Amounts represent activity recorded at BGE from March 12, 2012, the closing date of the merger, through September 30, 2012.
(c) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.
(d) For the nine months ended September 30, 2012 and 2011, utility taxes of $ 60 million and $ 20 million, respectively, are included in revenues and expenses for Generation. For the nine months ended September 30, 2012 and 2011, utility taxes of $182 million and $184 million, respectively, are included in revenues and expenses for ComEd. For the nine months ended September 30, 2012 and 2011, utility taxes of $108 million and $140 million, respectively, are included in revenues and expenses for PECO. For the period of March 12, 2012 through September 30, 2012, utility taxes of $42 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.

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	$ 3,832	$ (43)	$ 3,789	$ 3,102	$ —	$ 3,102
Midwest	3,600	19	3,619	4,151	—	4,151
New England	776	36	812	8	—	8
New York	394	(22)	372	—	—	—
ERCOT	1,073	1	1,074	507	—	507
Other Regions(b)	611	40	651	169	—	169
Total Revenues for Reportable Segments	$ 10,286	$ 31	$10,317	$ 7,937	$ —	$ 7,937
Other(c)	212	(20)	192	(18)	—	(18)
Total Generation Consolidated Operating Revenues	$ 10,498	$ 11	$10,509	$ 7,919	$ —	$ 7,919

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

(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	$ 2,605	$ (44)	$ 2,561	$ 2,567	$ —	$ 2,567
Midwest	2,291	19	2,310	2,704	—	2,704
New England	144	36	180	6	—	6
New York	82	(22)	60	—	—	—
ERCOT	311	1	312	94	—	94
Other Regions(b)	49	41	90	(10)	—	(10)
Total Revenues net of purchased power and fuel expense for Reportable Segments	$ 5,482	$ 31	$ 5,513	$ 5,361	$ —	$ 5,361
Other(c)	9	(31)	(22)	(237)	—	(237)
Total Generation Revenues net of purchased power and fuel expense	$ 5,491	$ —	$ 5,491	$ 5,124	$ —	$ 5,124

(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.

19. Subsequent Events (Exelon, PECO and BGE)

On October 29, 2012, a category 1 hurricane, Hurricane Sandy, interrupted electric service delivery to more than 850,000 customers and 325,000 customers in PECO's and BGE's service territories, respectively. Restoration efforts will include significant costs associated with employee overtime, support from other utilities and incremental equipment, contracted tree trimming crews and supplies. PECO and BGE estimate that restoration efforts will result in approximately $49 million to $55 million and $33 million to $37 million of incremental operating and maintenance expense, respectively, and $32 million to $36 million and $13 million to $14 million of incremental capital expenditures, respectively, for the fourth quarter.

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.

Executive Overview

Financial Results. The following consolidated financial results reflect the results of Exelon for the three and nine months ended September 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 September 30, 2012. All amounts presented below are before the impact of income taxes, except as noted.

	Three Months Ended September 30,							Favorable (Unfavorable) Variance
	2012						2011	
	Generation	ComEd	PECO	BGE	Other	Exelon	Exelon	
Operating revenues	$ 4,017	$1,484	$806	$720	$(462)	$6,565	$5,254	$ 1,311
Purchased power and fuel	2,122	678	326	373	(473)	3,026	2,121	(905)
Revenue net of purchased power and fuel(a)	1,895	806	480	347	11	3,539	3,133	406
Other operating expenses								
Operating and maintenance	1,415	350	199	201	(9)	2,156	1,413	(743)
Depreciation and amortization	207	157	55	68	13	500	332	(168)
Taxes other than income	109	81	48	48	4	290	207	(83)
Total other operating expenses	1,731	588	302	317	8	2,946	1,952	(994)
Equity in earnings of unconsolidated affiliates	10	—	—	—	—	10	—	10
Operating income	174	218	178	30	3	603	1,181	(578)
Other income and (deductions)								
Interest expense, net	(85)	(74)	(32)	(35)	(20)	(246)	(182)	(64)
Other, net	83	5	2	5	6	101	(142)	243
Total other income and (deductions)	(2)	(69)	(30)	(30)	(14)	(145)	(324)	179
Income (loss) before income taxes	172	149	148	—	(11)	458	857	(399)
Income taxes	85	59	25	—	(8)	161	255	94
Net income (loss)	87	90	123	—	(3)	297	602	(305)
Net (loss) income attributable to noncontrolling interests, preferred security dividends and preference stock dividends	(4)	—	1	4	—	1	1	—
Net income (loss) on common stock	$ 91	$ 90	$122	$ (4)	$ (3)	$ 296	$ 601	$ (305)

	Nine Months Ended September 30,							Favorable (Unfavorable) Variance
	2012						2011	
	Generation	ComEd	PECO	BGE	Other	Exelon	Exelon	
Operating revenues	$ 10,509	$4,154	$2,396	$1,388	$(1,242)	$17,205	$14,705	$ 2,500
Purchased power and fuel	5,018	1,886	1,033	727	(1,266)	7,398	5,836	(1,562)
Revenue net of purchased power and fuel (a)	5,491	2,268	1,363	661	24	9,807	8,869	938
Other operating expenses								
Operating and maintenance	3,756	1,000	574	423	196	5,949	3,863	(2,086)
Depreciation and amortization	564	458	161	157	36	1,376	987	(389)
Taxes other than income	272	224	122	104	15	737	602	(135)
Total other operating expenses	4,592	1,682	857	684	247	8,062	5,452	(2,610)
Equity in losses of unconsolidated affiliates	(69)	—	—	—	—	(69)	—	(69)
Operating income (loss)	830	586	506	(23)	(223)	1,676	3,417	(1,741)
Other income and (deductions)								
Interest expense, net	(223)	(230)	(94)	(77)	(73)	(697)	(545)	(152)
Other, net	185	12	6	14	36	253	54	199
Total other income and (deductions)	(38)	(218)	(88)	(63)	(37)	(444)	(491)	47
Income (loss) before income taxes	792	368	418	(86)	(260)	1,232	2,926	(1,694)
Income taxes	373	149	118	(37)	(158)	445	1,034	589
Net income (loss)	419	219	300	(49)	(102)	787	1,892	(1,105)
Net (loss) income attributable to noncontrolling interests, preferred security dividends and preference stock dividends	(6)	—	3	8	—	5	3	(2)
Net income (loss) on common stock	$ 425	$ 219	$ 297	$ (57)	$ (102)	$ 782	$ 1,889	$ (1,107)

(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 September 30, 2012 Compared to Three Months Ended September 30, 2011. Exelon's net income was $296 million for the three months ended September 30, 2012 as compared to $601 million for the three months ended September 30, 2011, and diluted earnings per average common share were $0.35 for the three months ended September 30, 2012 as compared to $0.90 for the three months ended September 30, 2011.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $406 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 $347 million for the three months ended September 30, 2012. Generation's operating revenue net of purchased power and fuel expense increased by $145 million primarily due to the New England, New York, ERCOT and Other Regions. These regions contributed

$195 million and did not previously have a significant impact on Generation's revenue net of purchased power and fuel expense prior to the Merger. Generation's results were also favorably impacted by $153 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 $73 million in the Mid-Atlantic region also due to the addition of Constellation's operations in 2012. Generation had mark-to-market gains of $16 million in 2012 from economic hedging activities, net of intercompany eliminations, compared to $91 million in mark-to-market losses in 2011. Offsetting these favorable impacts, Generation incurred $257 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 and lower capacity revenues.

ComEd's revenues net of purchased power and fuel expense decreased by $46 million primarily due to decreased cost recovery for regulatory required programs and lower electric distribution rates effective, June 20, 2012.

Operating and maintenance expense increased by $743 million primarily due to the addition of BGE and Constellation. In addition, operating and maintenance expense was unfavorably affected by the $278 million loss on the sale of three Maryland generating assets. Including Constellation and BGE, labor, other benefits, contracting and materials increased by $436 million and pension and non-pension postretirement benefit expenses increased by $73 million. In addition, BGE incurred $40 million of storm costs during the three months ended September 30, 2012. Increased operating and maintenance expense was partially offset by decreased storm costs in the ComEd and PECO service territories of $57 million and $23 million, respectively, and a decrease of $25 million at ComEd associated with regulatory required programs.

Depreciation and amortization expense increased by $168 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 across the operating companies.

Equity in earnings of unconsolidated affiliates was $10 million primarily due to net income generated from Exelon's equity investment in CENG, partially offset by 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 $64 million due to an increase in debt obligations as a result of the Merger and an increase in debt issued at Generation and BGE in 2012.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011. Exelon's net income was $782 million for the nine months ended September 30, 2012 as compared to $1,889 million for the nine months ended September 30, 2011, and diluted earnings per average common share were $0.97 for the nine months ended September 30, 2012 as compared to $2.84 for the nine months ended September 30, 2011. Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $938 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 $661 million from March 12, 2012 to September 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 $367 million primarily due to the New England, New York, ERCOT and Other Regions. These regions contributed $552 million and did not previously have a significant on Generation's revenue net of purchased power and fuel expense prior to the Merger. Generation's results were also favorably affected by $383 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 $276 million in 2012 from economic hedging activities, net of intercompany eliminations, compared to $363 million in mark-to-market losses in 2011. Offsetting these favorable impacts, Generation incurred $793 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 $394 million in the Midwest region due to lower realized power prices and lower capacity revenues.

PECO's operating revenues net of purchased power and fuel expense decreased by $73 million primarily as a result of unfavorable weather and a decline in electric load.

Operating and maintenance expense increased by $2,086 million primarily due to the addition of BGE and Constellation. In addition, operating and maintenance expense was unfavorably affected by the $278 million loss on the sale of three Maryland generating assets. Including Constellation and BGE, labor, other benefits, contracting and materials increased by $994 million, Constellation merger and integration costs increased by $187 million, and pension and non-pension postretirement benefits expense increased by $170 million. In addition, Exelon incurred $216 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, and BGE incurred $45 million of storm costs. Increased operating and maintenance expense was partially offset by decreased storm costs in the ComEd and PECO service territories of $78 million and $31 million, respectively.

Depreciation and amortization expense increased by $389 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 across the operating companies.

Equity in losses of unconsolidated affiliates was $69 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, partially offset by net income generated from Exelon's equity investment in CENG.

Interest expense increased by $152 million due to an increase in debt obligations as a result of the Merger and an increase in debt issued at Generation and BGE in 2012.

Exelon's results for the nine months ended September 30, 2011 were favorably affected by certain income tax-related matters. In 2012, Exelon recorded a $117 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 nine months ended September 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 September 30, 2012 were $658 million, or $0.77 per diluted share, compared with adjusted (non-GAAP) operating earnings of $743 million, or $1.12 per diluted share, for the same period in 2011. Exelon's adjusted (non-GAAP) operating earnings for the nine months ended September 30, 2012 were $1,783 million, or $2.21 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,219 million, or $3.34 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.

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 nine months ended September 30, 2012 as compared to the same period in 2011:

	Three Months Ended September 30,			
	2012		2011	
(All amounts after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income	$ 296	$ 0.35	$ 601	$ 0.90
Mark-to-Market Impact of Economic Hedging Activities(a)	(19)	(0.02)	55	0.08
Unrealized (Gains) Losses Related to NDT Fund Investments(b)	(38)	(0.04)	76	0.12
Plant Retirement and Divestitures(c)	193	0.22	2	—
Constellation Merger and Integration Costs(d)	36	0.04	11	0.02
Amortization of Commodity Contract Intangibles(e)	187	0.21	—	—
Amortization of the Fair Value of Certain Debt(f)	(3)	—	—	—
Other Acquisition Costs(g)	—	—	5	0.01
Wolf Hollow Acquisition(h)	—	—	(23)	(0.03)
Asset Retirement Obligation(i)	6	0.01	16	0.02
Adjusted (non-GAAP) Operating Earnings	$ 658	$ 0.77	$ 743	$ 1.12

	Nine Months Ended September 30,			
	2012		2011	
(All amounts after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income	$ 782	$ 0.97	$1,889	$ 2.84
Mark-to-Market Impact of Economic Hedging Activities(a)	(185)	(0.23)	219	0.34
Unrealized (Gains) Losses Related to NDT Fund Investments(b)	(54)	(0.07)	46	0.07
Plant Retirement and Divestitures(c)	200	0.25	29	0.04
Constellation Merger and Integration Costs(d)	211	0.26	26	0.04
Amortization of Commodity Contract Intangibles(e)	545	0.68	—	—
Amortization of the Fair Value of Certain Debt(f)	(7)	(0.01)	—	—
Other Acquisition Costs(g)	3	—	5	0.01
Wolf Hollow Acquisition(h)	—	—	(23)	(0.03)
Asset Retirement Obligation(i)	6	0.01	16	0.02
Reassessment of State Deferred Income Taxes(j)	(117)	(0.15)	—	—
Recovery of Costs Pursuant to the 2011 Distribution Rate Case Order(k)	—	—	(17)	(0.03)
Maryland Commitments(l)	227	0.28	—	—
FERC Settlement(m)	172	0.22	—	—
Non-Cash Charge Resulting from Illinois Tax Rate Change Legislation(n)	—	—	29	0.04
Adjusted (non-GAAP) Operating Earnings	$1,783	$ 2.21	$2,219	$ 3.34

(a) Reflects the impact of (gains) losses for the three and nine months ended September 30, 2012 (net of taxes of $(12) million and $(121) million, respectively) and for the three and nine months ended September 30, 2011 (net of taxes of $36 million and $144 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) losses for the three and nine months ended September 30, 2012 (net of taxes of $(76) million and $(122) million, respectively) and for the three and nine months ended September 30, 2011 (net of taxes of $141 million and $82 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) For 2012, primarily reflects the impact for the three and nine months ended September 30, 2012 (net of taxes of $120 million and $123 million, respectively) associated with the expected sale in the fourth quarter of 2012 of three generating stations associated with certain regulatory approvals for the merger. For 2011, primarily reflects incremental accelerated depreciation associated with the retirement of four fossil generating units and compensation for the three and nine months ended September 30, 2011 (net of taxes of $2 million and $19 million, respectively) for operating two of the units past their planned retirement date under a FERC-approved reliability-must-run rate schedule. 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 nine months ended September 30, 2012 (net of taxes of $52 million and $133 million, respectively) and for the three and nine months ended September 30, 2011 (net of taxes of $7 million and $17 million, respectively) 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 nine months ended September 30, 2012 (net of taxes of $121 million and $355 million, respectively) of the amortization of intangible assets, net, related to commodity 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 for the three and nine months ended September 30, 2012 (net of taxes of $(2) million and $(4) million, respectively) 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 certain costs incurred for the nine months ended September 30, 2012 associated with various acquisitions (net of taxes of $2 million).

(h) Reflects a non-cash bargain purchase gain (negative goodwill) for the three and nine months ended September 30, 2011 in connection with the acquisition of Wolf Hollow, net of acquisition costs (net of taxes of $15 million).

(i) Reflects an increase in Generation's decommissioning obligation for spent nuclear fuel at retired nuclear units for the three and nine months ended September 30, 2012 (net of taxes of $4 million) and for the three and nine months ended September 30, 2011 (net of taxes of $11 million).

(j) 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.

(k) 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.

(l) Reflects costs incurred for the nine months ended September 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.

(m) Reflects costs incurred for the nine months ended September 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.

(n) 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.

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

	Pre-tax Expense Three Months Ended September 30, 2012				
Merger and Integration Costs:	Generation(a)	ComEd	PECO	BGE(a)	Exelon(a)
Transaction(b)	$ —	$ —	$ —	$ —	$ —
Maryland Commitments	—	—	—	—	—
Employee-Related(c)	12	—	2	—	15
Other(d)	67	—	1	1	72
Total	$ 79	$ —	$ 3	$ 1	$ 87

	Pre-tax Expense Nine Months Ended September 30, 2012				
Merger and Integration Costs:	Generation(a)	ComEd	PECO	BGE(a)	Exelon(a)
Transaction(b)	$ —	$ —	$ —	$ —	$ 52
Maryland Commitments	35	—	—	139	328
Employee-Related(c)	98	—	9	—	116
Other(d)	150	2	4	5	175
Total	$ 283	$ 2	$ 13	$ 144	$ 671

(a) For Exelon, Generation and BGE, includes the operations of the acquired businesses from the date of the merger, March 12, 2012, through September 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 regulatory assets of $22 million and $22 million, respectively; the majority of these costs 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. ComEd established a regulatory asset of $12 million for certain other merger and integration costs, which are not included in the table above.

As of September 30, 2012, Exelon projects incurring total additional merger-related expenses, primarily in 2012 and 2013, of approximately $134 million.

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 new headquarters building in Baltimore may vary depending on the structure of the transaction.

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. This pending sale is part of one of the post-merger actions required as part of merger regulatory approvals. 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. Early on, the nuclear industry took a number of specific steps to respond, including actions requested by the Institute of Nuclear Power Operations (INPO) to perform tests that verified Generation's emergency equipment is available and functional, conduct walk-downs on its procedures related to critical safety equipment, confirm event response procedures and readiness to protect the spent fuel pool, and verify current qualifications of operators and support staff needed to implement the procedures. Generation has been addressing additional actions requested by INPO for improving and maintaining core and spent fuel pool cooling during an extended loss of power for at least 24 hours.

In April 2011, the NRC named six senior managers and staff to its task force for examining the agency's regulatory requirements, programs, processes, and implementation in light of information from the Fukushima Daiichi site in Japan, following the March 11 earthquake and tsunami (Task Force). On July 12, 2011, the 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.

Generation has assessed 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 through the required implementation deadline of December 31, 2016. However, until the specific requirements and guidance for each 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 as the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See ITEM 1A. RISK FACTORS of the Exelon 2011 Form 10-K for further discussion of the risk factors.

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. 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. The continued sluggish economy in the United

States has also led to a decline in demand for electricity. ComEd is projecting load volumes to remain essentially flat in 2012 compared to 2011, while PECO and BG&E are projecting a decline of 2.4% and 2.5%, respectively, in 2012 compared to 2011. The projected declines at PECO and BG&E are a result of energy efficiency initiatives and weak economic conditions in their service territories, in addition to reduced refinery load at PECO.

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

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 September 30, 2012, approximately 30%, or $3.1 billion, of the Registrants' aggregate total commitments were with European banks. The credit facilities include $9.8 billion in aggregate total commitments of which $7.9 billion was available as of September 30, 2012. There were no borrowings under the Registrants' credit facilities as of September 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 non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 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 September 30, 2012, the percentage of expected generation hedged was 98%-101%, 87%-90%, 55%-58%, and 20%-23% for 2012, 2013, 2014 and 2015, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity, 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 57% 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 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. In 2008, Generation announced a series of planned power uprates across its nuclear fleet that, if and when completed, would result in between 1,125 and 1,200 MWs at an overnight cost of approximately $3.4 billion in 2013 dollars, of which approximately $950 million has been spent through September 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.

The uprates are being undertaken pursuant to an organized, strategically sequenced implementation plan. The implementation effort includes a periodic review and refinement of the plan in light of changing market conditions. The amount of expenditures to implement the plan will be determined on a project-by-project basis in accordance with Exelon's normal project evaluation standards and ultimately will depend on economic and policy developments and projected sources and uses of funds. Based on recent reviews, the nuclear uprate implementation plan was adjusted during the second and third quarters of 2012, primarily as a result of market conditions, resulting in the deferral or cancellation of certain projects. The ability to implement several projects requires the successful resolution of various technical issues. The resolution of these issues may further affect the timing and amount of the power increases associated with the power uprate initiative.

Uprate projects, representing approximately 75% of the planned uprate MWs, are either complete or underway at the Limerick 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 an additional extended power uprate project at Limerick currently scheduled to begin in 2017. All projects that are undertaken are expected to be completed by the end of 2021. From the program announcement through September 30, 2012, Generation has added 250 MWs of nuclear generation through its uprate program, with another 15 MWs scheduled to be added during the remainder of 2012.

Generation Renewable Development. Generation is constructing multiple wind facilities in 2012, resulting in approximately 400 MWs of additional renewable generation. Total costs for the facilities are expected to be approximately $710 million. Total costs incurred through September 30, 2012 were $555 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 September 30, 2012 were $512 million. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

New Nuclear Site Development. On Aug. 28, 2012, Exelon halted efforts to gain initial federal regulatory approvals for new nuclear construction in Victoria County, Texas. The company notified the Nuclear Regulatory Commission that it has withdrawn its Early Site Permit application for an 11,500-acre tract southeast of Victoria. The action is in response to low natural gas prices and economic and market conditions that have made construction of new merchant nuclear power plants in competitive markets uneconomical now and for the foreseeable future. Exelon originally submitted an application for a combined construction and operating license for the Victoria County site in 2008, but never made a decision to build a nuclear plant there. In 2010, the company applied for an Early Site Permit, a change in licensing strategy that allowed Exelon to continue with some aspects of site evaluation and regulatory approvals while deferring a construction decision for up to 20 years. The withdrawal of the license brings an end to all project activity.

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, ComEd, PECO and BGE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $2.0 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. Generation has a bilateral credit facility with aggregate maximum availability of $0.3 billion.

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 August 10, 2012, Exelon Corporate, Generation, PECO and BGE amended and extended their respective unsecured syndicated revolving credit facilities, with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively, through August 10, 2017.

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). As further legislation and regulation imposing requirements on emissions of air pollutants are promulgated, Exelon's 2020 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.

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.

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 — 2014 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. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA had exceeded its authority in certain material aspects with respect to CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. On October 5, 2012, the DOJ, on behalf of the U.S. EPA, filed a petition for a re-hearing *en banc* (i.e., before all the D.C. Circuit Court judges) of the panel's decision. On the same date Exelon joined with other industry members in a petition for an *en banc* review. Due to the uncertainties of the on-going litigation, and the content and timing of a final CSAPR after remand, Exelon cannot predict the impact on power prices. Exelon continues to believe that the CSAPR is a valid exercise of the U.S. EPA's authority and discretion under the Clean Air Act.

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 been granted permission by the Court to intervene in support of the rule. A decision by the Court is not expected until some time in 2013.

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 has entered into an agreement to sell these generating stations. The transaction, which is subject to approval by FERC and DOJ, is expected to close in the fourth quarter of 2012. It is anticipated that these plants are well positioned to comply with CSAPR and MATS, since Maryland has adopted SO2, NOx, 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 CO2 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 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.

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 29, 2012, the ICC issued its final Order (May Order) in that proceeding. The May 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 a subsequent 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 May Order.

On June 22, 2012, the ICC granted an expedited rehearing on the issues of 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. On October 3, 2012, the ICC issued its final order (Rehearing Order) in ComEd's expedited rehearing. The Rehearing Order adopted ComEd's position on the return on its pension asset, resulting in an increase in ComEd's annual revenue requirement. In two other areas, the ICC ruled against ComEd by reaffirming use of an average rather than year-end rate base in ComEd's reconciliation revenue requirement; and amending its prior order to provide a short-term debt rate as the appropriate interest rate to apply to under/over recoveries of incurred costs. ComEd filed an appeal of the May Order and the Rehearing Order in court on October 4, 2012. While the ICC's October 3, 2012, ruling to allow recovery on the pension asset as proposed by ComEd is important, this decision does not eliminate all of the revenue shortfall resulting from the numerous other problematic findings in the orders. The relevant findings are contrary to the provisions of the EIMA, and are the subject to ComEd's appeals of the May Order and the Rehearing Order. These findings, in the aggregate, will result in a projected revenue deficit of about $100 million per year in 2014 and beyond.

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 filing with the ICC 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. However, as a result of the Rehearing Order above, ComEd is delaying certain elements of the AMI Deployment Plan, including the delay of installation of additional smart meters. ComEd has outlined the new deployment schedule within testimony provided in the AMI Plan Rehearing on October 3, 2012. As a result of the Rehearing Order ComEd has deferred approximately $50 million of the 2012 AMI Deployment Plan and $15 million of planned capital investment to future years. An Order from the ICC on ComEd's revised deployment plan is due by December 5, 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 September 30, 2012 and December 31, 2011, ComEd recorded an estimated net regulatory asset of $74 million and $84 million, respectively, which represents the ICC's approved distribution formula and associated rulings as of September 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 nine months ended September 30, 2012. The evidentiary hearing in ComEd's 2011 reconciliation rate case was held on September 25, 2012, and a final order is 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 the ICC's approval of 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. The Illinois Supreme Court denied the Petition on September 26, 2012, and returned the matter to the ICC to calculate a refund amount. 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 over-the-counter swaps (Swaps), including mandatory clearing, exchange trading, margin requirements, and other transparency requirements. The Dodd-Frank Act, however, also preserves the ability of end users in the energy industry to hedge their risks. In April 2012, the CFTC issued its rule defining swap dealers and major swap participants. Exelon has determined that it will conduct its commercial business in a manner that does not require registration as a swap dealer or major swap participant. Notwithstanding, there are additional rulemakings that have not yet been issued, including the capital and margin rules, which will further define the scope of the regulations and provide clarity as to the impact on the Registrants' business, as well as to potential new opportunities. Depending on these final rules, the Registrants could be subject to significant new obligations.

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

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

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

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. 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.

2012 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 27, 2012, BGE filed an application for increases to its electric and gas base rates with the MDPSC. The requested rate of return on equity in the application is 10.5%. On October, 22, 2012, BGE updated its application to request an increase of $131 million and $45 million to its electric and gas base rates, respectively. 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.

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. Ameren has filed for rehearing regarding the July 2012 FERC order. ComEd believes that the FERC order authorizing its transmission formula rate is distinguishable from the circumstances that led to the July 2012 FERC order in the Ameren case. However, if ComEd were required to exclude acquisition premiums/ goodwill from its transmission formula rate, the impact could be material to ComEd's results of operations and cash flows.

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 September 30, 2012, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2011.

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Results of Operations

Net Income (Loss) on Common Stock by Registrant

	Three Months Ended September 30, 2012(a)	Three Months Ended September 30, 2011	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2012(a)	Nine Months Ended September 30, 2011	Favorable (Unfavorable) Variance
Exelon	$ 296	$ 601	$ (305)	$ 782	$ 1,889	$ (1,107)
Generation	91	386	(295)	425	1,325	(900)
ComEd	90	112	(22)	219	295	(76)
PECO	122	104	18	297	311	(14)
BGE	(4)	(2)	(2)	(24)	89	(113)

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

Results of Operations — Generation

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	Favorable (Unfavorable) Variance
Operating revenues	$ 4,017	$ 2,821	$ 1,196	$10,509	$7,919	$ 2,590
Purchased power and fuel expense	2,122	1,071	(1,051)	5,018	2,795	(2,223)
Revenue net of purchased power and fuel(a)	1,895	1,750	145	5,491	5,124	367
Other operating expenses						
Operating and maintenance	1,415	790	(625)	3,756	2,306	(1,450)
Depreciation and amortization	207	139	(68)	564	416	(148)
Taxes other than income	109	67	(42)	272	199	(73)
Total other operating expenses	1,731	996	(735)	4,592	2,921	(1,671)
Equity in earnings (losses) of unconsolidated affiliates	10	—	10	(69)	—	(69)
Operating income	174	754	(580)	830	2,203	(1,373)
Other income and (deductions)						
Interest expense	(85)	(37)	(48)	(223)	(128)	(95)
Other, net	83	(164)	247	185	(12)	197
Total other income and (deductions)	(2)	(201)	199	(38)	(140)	102
Income before income taxes	172	553	(381)	792	2,063	(1,271)
Income taxes	85	167	82	373	738	365
Net income	87	386	(299)	419	1,325	(906)
Net loss attributable to noncontrolling interests	(4)	—	4	(6)	—	6
Net income on common stock	$ 91	$ 386	$ (295)	$ 425	$1,325	$ (900)

(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 September 30, 2012 Compared to Three Months Ended September 30, 2011. Generation's net income decreased compared to the same period in 2011 due to the impairment of certain generating assets in 2012 and higher operating expenses; offset by favorable NDT fund performance and 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. See Note 3 for additional information regarding the impairment of certain generating assets in 2012.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011. Generation's net income decreased compared to the same period in 2011 due to the impairment of certain generating assets in 2012, higher operating expenses and the amortization of acquired energy contracts with CENG recorded at fair value at the merger date; offset by higher revenues, net of purchased power and fuel expense and favorable NDT fund performance. 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. See Note 3 for additional information regarding the impairment of certain generating assets 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.

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

	Three Months Ended September 30,			
	2012(a)	2011	Variance	% Change
Mid-Atlantic(b)	$ 908	$ 835	$ 73	8.7%
Midwest(c)	729	852	(123)	(14.4%)
New England	81	1	80	n.m.
New York	13	—	13	n.m.
ERCOT	159	103	56	54.4%
Other Regions(d)	42	(4)	46	n.m.
Total electric revenue net of purchased power and fuel expense	$ 1,932	$ 1,787	$ 145	8.1%
Proprietary Trading	(1)	2	(3)	(150.0%)
Mark-to-market gains (losses)	17	(91)	108	(118.7%)
Other(e)	(53)	52	(105)	n.m.
Total revenue net of purchased power and fuel expense	$ 1,895	$ 1,750	$ 145	8.3%

	Nine Months Ended September 30, 2012(a)	Nine Months Ended September 30, 2011	Variance	% Change
Mid-Atlantic(b)	$2,561	$2,567	$ (6)	(0.2%)
Midwest(c)	2,310	2,704	(394)	(14.6%)
New England	180	6	174	n.m.
New York	60	—	60	n.m.
ERCOT	312	94	218	n.m.
Other Regions(d)	90	(10)	100	n.m.
Total electric revenue net of purchased power and fuel expense	$5,513	$5,361	$ 152	2.8%
Proprietary Trading	10	24	(14)	(58.3%)
Mark-to-market gains (losses)	276	(363)	639	n.m.
Other(e)	(308)	102	(410)	n.m.
Total revenue net of purchased power and fuel expense	$5,491	$5,124	$ 367	7.2%

(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 of $257 million and $793 million pre-tax for the three and nine months ended September 30, 2012.

Generation’s supply sources by region are summarized below:

Supply source (GWh)	Three Months Ended September 30, 2012(a)	2011	Variance	% Change
Nuclear generation(b)				
Mid-Atlantic	11,449	12,158	(709)	(5.8%)
Midwest	23,132	23,887	(755)	(3.2%)
Total Nuclear Generation	34,581	36,045	(1,464)	(4.1%)
Fossil and Renewables(b)				
Mid-Atlantic(b)(d)	2,547	1,722	825	47.9%
Midwest	171	88	83	94.3%
New England	3,953	2	3,951	n.m
New York	—	—	—	n.m
ERCOT(e)	2,410	1,214	1,196	98.5%
Other Regions(f)	1,813	249	1,564	n.m
Total Fossil and Renewables	10,894	3,275	7,619	n.m.
Purchased power				
Mid-Atlantic(c)	6,811	702	6,109	n.m
Midwest	3,035	1,756	1,279	72.8%
New England	1,961	—	1,961	n.m
New York(c)	4,026	—	4,026	n.m
ERCOT(e)	7,741	2,928	4,813	n.m
Other Regions(f)	5,372	887	4,485	n.m
Total Purchased Power	28,946	6,273	22,673	n.m.
Total supply/sales by region(g)				
Mid-Atlantic(h)	20,807	14,582	6,225	42.7%
Midwest(i)	26,338	25,731	607	2.4%
New England	5,914	2	5,912	n.m
New York	4,026	—	4,026	n.m
ERCOT	10,151	4,142	6,009	145.1%
Other Regions(f)	7,185	1,136	6,049	n.m
Total supply/sales by region	74,421	45,593	28,828	63.2%

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Supply source (GWh)	Nine Months Ended September 30, 2012(a)	2011	Variance	% Change
Nuclear generation(b)				
Mid-Atlantic	35,790	35,700	90	0.3%
Midwest	69,190	68,704	486	0.7%
Total Nuclear Generation	104,980	104,404	576	0.6%
Fossil and Renewables(b)				
Mid-Atlantic(b)(d)	6,654	5,936	718	12.1%
Midwest	671	408	263	64.5%
New England	7,597	8	7,589	n.m.
New York	—	—	—	n.m.
ERCOT(e)	5,427	1,572	3,855	n.m.
Other Regions(f)	4,555	1,037	3,518	n.m.
Total Fossil and Renewables	24,904	8,961	15,943	n.m.
Purchased power				
Mid-Atlantic(c)	16,498	2,159	14,339	n.m.
Midwest	7,145	4,827	2,318	48.0%
New England	6,966	—	6,966	n.m.
New York(c)	7,779	—	7,779	n.m.
ERCOT(e)	17,259	6,387	10,872	n.m.
Other Regions(f)	13,153	2,021	11,132	n.m.
Total Purchased Power	68,800	15,394	53,406	n.m.
Total supply/sales by region(g)				
Mid-Atlantic(h)	58,942	43,795	15,147	34.6%
Midwest(i)	77,006	73,939	3,067	4.1%
New England	14,563	8	14,555	n.m.
New York	7,779	—	7,779	n.m.
ERCOT	22,686	7,959	14,727	n.m.
Other Regions(f)	17,708	3,058	14,650	n.m.
Total supply/sales by region	198,684	128,759	69,925	54.3%

(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 3,126 GWh and 6,670 GWh in the Mid-Atlantic and 2,997 GWh and 6,536 GWh in New York as a result of the PPA with CENG for the three and nine months ended September 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 period ending June 30, 2011 and through the acquisition date of August 24, 2011, and included within Fossil and Renewables subsequent to the acquisition date.
(f) Other Regions includes South, West and Canada, which are not considered individually significant.
(g) Excludes physical proprietary trading volumes of 4,352 GWh and 1,679 GWh for the three months ended September 30, 2012 and 2011, respectively, 9,981 GWh and 4,508 GWh for the nine months ended September 30, 2012 and 2011, respectively.
(h) Includes sales to PECO through the competitive procurement process of 2,350 GWh and 1,928 GWh for the three months ended September 30, 2012 and 2011, respectively, and 5,837 GWh and 5,597 GWh for the nine months ended September 30, 2012 and 2011, respectively. Sales to BGE of 1,075 GWh and 2,410 GWh were included for the three and nine months ended September 30, 2012.
(i) Includes sales to ComEd under the RFP procurement of 1,077 GWh and 3,449 GWh for the three months ended September 30, 2012 and 2011, respectively, and 4,152 GWh and 7,050 GWh for the nine months ended September 30, 2012 and 2011, respectively.

The following table presents electric revenue net of purchased power and fuel expense per MWh of electricity sold during the three and nine months ended September 30, 2012 as compared to the three and nine months ended September 30, 2011.

$/MWh	Three Months Ended September 30, 2012(a)	Three Months Ended September 30, 2011	% Change
Mid-Atlantic(b)	$ 43.64	$57.26	(23.8%)
Midwest(c)	27.68	33.15	(16.5%)
New England	13.70	n.m.	n.m.
New York	3.23	n.m.	n.m.
ERCOT	15.66	24.85	(37.0%)
Other Regions(d)	5.85	(4.85)	n.m.
Electric revenue net of purchased power and fuel expense per MWh(e)(f)	25.96	39.19	(33.8%)

$/MWh(a)	Nine Months Ended September 30, 2012(a)	Nine Months Ended September 30, 2011	% Change
Mid-Atlantic(b)	$ 43.48	$58.61	(25.8%)
Midwest(c)	30.00	36.57	(18.0%)
New England	12.22	n.m.	n.m.
New York	7.71	n.m.	n.m.
ERCOT	13.75	11.94	15.2%
Other Regions(d)	5.08	(3.27)	n.m.
Electric revenue net of purchased power and fuel expense per MWh(e)(f)	27.75	41.64	(33.4%)

(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 $173 million (2,350 GWh) and $141 million (1,928 GWh) for the three months ended September 30, 2012 and 2011 respectively. Includes sales to PECO of $408 million (5,837 GWh) and $400 million (5,597 GWh) for the nine months ended September 30, 2012 and 2011 respectively. Sales to BGE of $120 million (1,075 GWh) and $222 million (2,410 GWh) were included for the three and nine months ended September 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 $47 million (1,077 GWh) and $67 million (1,653 GWh) and settlements of the ComEd swap of $133 million and $92 million for the three months ended September 30, 2012 and 2011, respectively. Includes sales to ComEd of $162 million (4,152 GWh) and $137 million (3,449 GWh) and settlements of the ComEd swap of $469 million and $312 million for the nine months ended September 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 nine months ended September 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 September 30, 2012 Compared to Three Months Ended September 30, 2011. The increase in revenue net of purchased power and fuel expense in the Mid-Atlantic of $73 million was primarily due to the addition of Constellation in 2012 and higher capacity revenues, partially offset by lower realized power prices.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011. The decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic of $6 million was primarily due to lower realized power prices, partially offset by higher capacity revenues and the addition of Constellation in 2012.

Midwest

Three Months Ended September 30, 2012 Compared to Three Months Ended September 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 and lower realized power prices, partially offset by decreased congestion costs.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011. The decrease in revenue net of purchased power and fuel expense in the Midwest of $394 million was primarily due to lower realized power prices and lower capacity revenues, partially offset by decreased congestion costs.

New England.

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011. The $80 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.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011. The $174 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 September 30, 2012 Compared to Three Months Ended September 30, 2011. The $13 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.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011. The $60 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 September 30, 2012 Compared to Three Months Ended September 30, 2011. The $56 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily as a result of the Constellation merger, partially offset by a decrease in revenue net of purchased power and fuel expense in the legacy Generation ERCOT due to extreme weather and favorable market conditions in August 2011.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011. The $218 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily as a result of the Constellation merger, partially offset by a decrease in revenue net of purchased power and fuel expense in the legacy Generation ERCOT portfolio primarily driven by the performance of our generating units during the extreme weather events that occurred in Texas in February and August 2011.

Other Regions.

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011. The $46 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of the Constellation merger.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011. The $100 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 September 30, 2012 Compared to Three Months Ended September 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 $16 million for the three months ended September 30, 2012 compared to losses of $91 million for the three months ended September 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.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 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 $276 million for the nine months ended September 30, 2012 compared to losses of $363 million for the nine months ended September 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 September 30, 2012 Compared to Three Months Ended September 30, 2011. The $104 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.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011. The $410 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 nine months ended September 30, 2012 as compared to the same periods in September 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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Nuclear fleet capacity factor(a)	90.7%	95.8%	92.6%	93.4%
Nuclear fleet production cost per MWh(a)	$ 19.04	$ 17.35	$ 19.19	$ 18.47

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC, and CENG's nuclear facilities, which are operated by CENG. Reflects ownership percentage of stations operated by Exelon.

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011. The nuclear fleet capacity factor decreased primarily due to more non-refueling and refueling outage days, excluding Salem outages, during the three months ended September 30, 2012 compared to the same period in 2011. For the three months ended September 30, 2012 and 2011, non-refueling outage days totaled 40 and 3, respectively. During the same periods, refueling outage days totaled 43 and 33, respectively. Lower number of net MWhs generated, higher nuclear fuel costs and higher plant operating and maintenance expense resulted in a higher production cost per MWh for the three months ended September 30, 2012 as compared to the same period in 2011.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011. The nuclear fleet capacity factor decreased primarily due to more non-refueling outage days, partially offset by fewer refueling outage days, excluding Salem outages, during the nine months ended September 30, 2012 compared to the same period in 2011. For the nine months ended September 30, 2012 and 2011, non-refueling outage days totaled 72 and 41, respectively. During the same periods, refueling outage days totaled 161 and 180, 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 and higher plant operating and maintenance expense resulted in higher production cost per MWh for the nine months ended September 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 nine months ended September 30, 2012 compared to the same period in 2011, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Labor, other benefits, contracting and materials	$ 239	$ 533
Impairment of certain generating assets(a)	278	278
FERC settlement(b)	—	195
Constellation merger and integration costs	20	132
Corporate allocations(c)	60	168
Pension and non-pension postretirement benefits expense	43	97
Maryland commitments(d)	—	35
Nuclear refueling outage costs, including the co-owned Salem plant(e)	3	(48)
Other	(18)	60
Increase in operating and maintenance expense	$ 625	$ 1,450

(a) See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.
(b) 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.
(c) Reflects the impact of an increased share of corporate allocated costs due to the merger.
(d) Reflects costs incurred as part of the Maryland order approving the merger transaction.
(e) Reflects the impact of decreased planned refueling outage days during the nine months ended September 30, 2012.

Depreciation and Amortization

The increase in depreciation and amortization for the three and nine months ended September 30, 2012 as compared to the three and nine months ended September 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 nine months ended September 30, 2012 as compared to the three and nine months ended September 30, 2011 was primarily due to the addition of Constellation's financial results in 2012.

Equity in Earnings (Losses) of Unconsolidated Affiliates

Equity in earnings (losses) of unconsolidated affiliates for the three and nine months ended September 30, 2012 primarily reflected the net income generated from Exelon's equity investment in CENG, 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 nine months ended September 30, 2012 as compared to the three and nine months ended September 30, 2011 was primarily due to the increase in long-term debt as a result of the merger. The increase in interest expense was also due to debt issued in 2012. See Note 9 of the Combined Notes to Consolidated Financial Statements for additional information.

Other, Net

Three Months Ended September 30, 2012 Compared to Three Months Ended September 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 $48 million of income in 2012 compared to $71 million of expense in 2011 related to the contractual elimination of income tax expense in 2012 and income tax benefit in 2011 associated with the NDT funds of the Regulatory Agreement Units; $43 million of credit facility termination fees recorded in 2012 and a $36 million bargain purchase gain associated with the August 2011 acquisition of Wolf Hollow.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 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 $100 million of income in 2012 and $25 million of expense in 2011, related to the contractual elimination of income tax expense in 2012 and income tax benefit in 2011 associated with the NDT funds of the Regulatory Agreement Units; $85 million of credit facility termination fees recorded in 2012, a $36 million bargain purchase gain associated with the August 2011 acquisition of Wolf Hollow and the impact of a $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 nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net unrealized gains (losses) on decommissioning trust funds	$ 71	$ (141)	$ 101	$ (88)
Net realized gains (losses) on sale of decommissioning trust funds	$ 1	$ (1)	$ 41	$ (3)

Effective Income Tax Rate

The effective income tax rate was 49.4% and 47.1% for the three and nine months ended September 30, 2012, respectively, compared to 30.2% and 35.8% 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 September 30,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2012	2011		2012	2011	
Operating revenues	$ 1,484	$ 1,784	$ (300)	$ 4,154	$ 4,694	$ (540)
Purchased power expense	678	932	254	1,886	2,436	550
Revenue net of purchased power expense(a)	806	852	(46)	2,268	2,258	10
Other operating expenses						
Operating and maintenance	350	396	46	1,000	930	(70)
Depreciation and amortization	157	135	(22)	458	405	(53)
Taxes other than income	81	78	(3)	224	226	2
Total other operating expenses	588	609	21	1,682	1,561	(121)
Operating income	218	243	(25)	586	697	(111)
Other income and (deductions)						
Interest expense, net	(74)	(86)	12	(230)	(257)	27
Other, net	5	16	(11)	12	24	(12)
Total other income and (deductions)	(69)	(70)	1	(218)	(233)	15
Income before income taxes	149	173	(24)	368	464	(96)
Income taxes	59	61	2	149	169	20
Net income	$ 90	$ 112	$ (22)	$ 219	$ 295	$ (76)

(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.

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Net Income

Three Months Ended September 30, 2012, Compared to Three Months Ended September 30, 2011. ComEd's net income for the three months ended September 30, 2012, was lower than the same period in 2011 primarily due to the result of the May 29, 2012, final Order issued by the ICC in ComEd's 2011 formula rate proceeding under EIMA. Offsetting the impacts of the ICC Order, ComEd experienced reduced operating and maintenance expenses in 2012 net of increased depreciation and amortization. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

Nine Months Ended September 30, 2012, Compared to Nine Months Ended September 30, 2011. ComEd's net income for the nine months ended September 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 1,453,061 and 249,714 at September 30, 2012, and 2011, respectively, representing 38% and 7% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 64% and 62% of ComEd's retail kWh sales for the three and nine months ended September 30, 2012, respectively, as compared to 53% and 54% for the three and nine months ended September 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 continue to increase. The City of Chicago and other municipalities are also considering similar referenda.

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

	Three Months Ended September 30, 2012 Increase (Decrease)	Nine Months Ended September 30, 2012 Increase (Decrease)
Transmission	$ 7	$ 23
Volume — delivery	2	(4)
Weather — delivery	—	—
Discrete impacts of the 2012 Distribution Rate Case Order	—	(88)
Revenues subject to refund, net	(17)	5
Electric distribution rates	(20)	48
Regulatory required programs	(25)	17
Other	7	9
Total increase (decrease)	$ (46)	$ 10

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 nine months ended September 30, 2012. This decrease was slightly offset by an increase for the three months ended September 30, 2012, compared to the same periods in 2011.

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 spite of experiencing slightly lower than normal temperatures in September 2012, Illinois experienced the warmest January through August period on record in 2012. While the third quarter of 2012 saw an increase in weather related deliveries, the impact on revenues was offset by a decrease in pricing. For the nine months ended September 30, 2012, the increase in revenues net of purchased power expense for the second and third quarters 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 nine months ended September 30, 2012 and 2011, consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2012**	**2011**	**Normal**	**From 2011**	**From Normal**
Three Months Ended September 30,					
Heating Degree-Days	107	147	119	(27.2)%	(10.1)%
Cooling Degree-Days	859	785	613	9.4%	40.1%
Nine Months Ended September 30,					
Heating Degree-Days	3,035	4,302	4,048	(29.5)%	(25.0)%
Cooling Degree-Days	1,321	1,022	831	29.3%	59.0%

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 29, 2012, the ICC issued its final Order (May Order) in the proceeding to establish ComEd's formula rate under EIMA. The Order reduced the annual revenue requirement by $168 million by modifying or eliminating some of the elements of the formula. On October 3, 2012, the ICC issued an order on remand (Rehearing Order) overturning portions of the May Order. ComEd expects to record an increase in revenue of approximately $135 million in the fourth quarter of 2012 consistent with the terms of the Rehearing Order. 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. During the three and nine months ended September 30, 2012, ComEd did not record revenues subject to refund associated with any matters. 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. In addition, ComEd began recording revenue subject to refund on June 1, 2010, relating to the recovery of Cash Working Capital (CWC) through its energy procurement rider. Based on the 2010 Rate Case order as well as the proceeding on remand associated with the Court order, during the third quarter 2011 ComEd reduced its revenue subject to refund reserve. See Note 4 of the Combined Notes to Consolidated Financial Statements.

Electric distribution rates

The ICC issued an 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 nine months ended September 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.

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.

Other

Other revenues were higher during the three and nine months ended September 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 costs associated with MGP sites.

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Operating and Maintenance Expense

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Increase (Decrease)	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	Increase (Decrease)
Operating and maintenance expense — baseline	$ 332	$ 353	$ (21)	$ 899	$ 846	$ 53
Operating and maintenance expense — regulatory required programs(a)	18	43	(25)	101	84	17
Total operating and maintenance expense	$ 350	$ 396	$ (46)	$ 1,000	$ 930	$ 70

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

The changes in operating and maintenance expense for the three and nine months ended September 30, 2012 compared to the same periods in 2011, consisted of the following:

	Three Months Ended September 30 Increase (Decrease)	Nine Months Ended September 30 Increase (Decrease)
Baseline		
Discrete impacts from 2010 Rate Case order(a)	$ —	$ 32
Labor, other benefits, contracting and materials(b)	24	69
Pension and non-pension postretirement benefits expense	15	33
Storm Related Costs(d)	(57)	(78)
Other	(3)	(3)
	(21)	53
Regulatory required programs		
Energy efficiency and demand response programs	(14)	34
Purchased power administrative costs	(11)	(7)
Uncollectible accounts expense — provision	—	(13)
Uncollectible accounts expense — recovery, net(c)	—	3
	(25)	17
Increase (Decrease) in operating and maintenance expense	$ (46)	$ 70

(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.

(d) Under EIMA, ComEd may recover costs associated with certain one-time events, such as large storms, over a five-year period. During the fourth quarter of 2011, ComEd recorded a net reduction in operating and maintenance expense for costs related to three significant third quarter 2011 storms.

Depreciation and Amortization Expense

Depreciation and amortization expense increased during the three and nine months ended September 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 and September 2012 to defer significant storm costs pursuant to EIMA.

Taxes Other Than Income

Taxes other than income taxes decreased for the nine months ended September 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 nine months ended September 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 39.6% for the three months ended September 30, 2012 compared to 35.3% for the same period during 2011. The effective income tax rate was 40.5% for the nine months ended September 30, 2012 compared to 36.4% 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 September 30, 2012	2011	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)				
Residential	9,265	8,877	4.4%	1.4%
Small commercial & industrial	8,939	8,811	1.5%	(0.1)%
Large commercial & industrial	7,506	7,494	0.2%	(0.8)%
Public authorities & electric railroads	314	303	3.6%	3.3%
Total Retail	26,024	25,485	2.1%	0.2%

Retail Deliveries to customers (in GWhs)	Nine Months Ended September 30, 2012	2011	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)				
Residential	22,345	22,108	1.1%	(0.5)%
Small commercial & industrial	24,742	24,648	0.4%	(0.2)%
Large commercial & industrial	21,048	21,011	0.2%	0.1%
Public authorities & electric railroads	932	919	1.4%	3.4%
Total Retail	69,067	68,686	0.6%	(0.1)%

Number of Electric Customers	As of September 30, 2012	2011
Residential	3,450,364	3,439,704
Small commercial & industrial	365,245	364,917
Large commercial & industrial	1,986	2,041
Public authorities & electric railroads	4,795	4,801
Total	3,822,390	3,811,463

	Three Months Ended September 30,			Nine Months Ended September 30,		
Electric Revenue	2012	2011	% Change	2012	2011	% Change
Retail Delivery and Sales(a)						
Residential	$ 876	$ 1,112	(21.2)%	$2,372	$2,746	(13.6)%
Small commercial & industrial	344	410	(16.1)%	997	1,177	(15.3)%
Large commercial & industrial	102	102	0.0%	296	288	2.8%
Public authorities & electric railroads	11	12	(8.3)%	32	38	(15.8)%
Total Retail	1,333	1,636	(18.5)%	3,697	4,249	(13.0)%
Other Revenue(b)	151	148	2.0%	457	445	2.7%
Total Electric Revenues	$ 1,484	$ 1,784	(16.8)%	$4,154	$4,694	(11.5)%

(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 September 30, 2012	Three Months Ended September 30, 2011	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	Favorable (Unfavorable) Variance
Operating revenues	$ 806	$ 946	$ (140)	$ 2,396	$ 2,942	$ (546)
Purchased power and fuel	326	464	138	1,033	1,506	473
Revenue net of purchased power and fuel(a)	480	482	(2)	1,363	1,436	(73)
Other operating expenses						
Operating and maintenance	199	219	20	574	597	23
Depreciation and amortization	55	51	(4)	161	150	(11)
Taxes other than income	48	59	11	122	165	43
Total other operating expenses	302	329	27	857	912	55
Operating income	178	153	25	506	524	(18)
Other income and (deductions)						
Interest expense, net	(32)	(34)	2	(94)	(102)	8
Other, net	2	3	(1)	6	11	(5)
Total other income and (deductions)	(30)	(31)	1	(88)	(91)	3
Income before income taxes	148	122	26	418	433	(15)
Income taxes	25	17	(8)	118	119	1
Net income	123	105	18	300	314	(14)
Preferred security dividends	1	1	—	3	3	—
Net income on common stock	$ 122	$ 104	$ 18	$ 297	$ 311	$ (14)

(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 September 30, 2012 Compared to Three Months Ended September 30, 2011. The increase in net income was primarily due to decreased storm expenses in 2012. The increase was partially offset by lower electric revenue net of purchase power expense due to a decline in load.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011. The decrease in net income was primarily due to unfavorable weather and a decline in electric load. The decrease in net income was partially offset by lower operating and maintenance expenses, taxes other than income and interest expense. The decrease in operating and maintenance expense was primarily due to lower storm costs.

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 464,800 and 351,500 at September 30, 2012 and 2011, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 65% of PECO's retail kWh sales for the three and nine months ended September 30, 2012, compared to 60% and 54% for the three and nine months ended September 30, 2011. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 48,600 and 20,600 at September 30, 2012 and 2011, respectively. Deliveries purchased from competitive natural gas suppliers represented 69% and 47% of PECO's mmcf sales for the three and nine months ended September 30, 2012, respectively, compared to 67% and 42% for the three and nine months ended September 30, 2011.

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

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ 4	$—	$ 4
Volume	(10)	—	(10)
Pricing	(8)	—	(8)
Regulatory required programs	18	—	18
Other	(6)	—	(6)
Total decrease	$ (2)	$—	$ (2)

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

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ (26)	$(25)	$(51)
Volume	(23)	1	(22)
Pricing	(1)	3	2
Regulatory required programs	22	—	22
Other	(24)	—	(24)
Total decrease	$ (52)	$(21)	$(73)

Weather

The demand for electricity and gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and gas. Conversely, mild weather reduces demand. During the three months ended September 30, 2012 compared to the same period in 2011, electric revenues net of purchased power were higher due to the impact of favorable weather conditions in PECO's service territory during the third quarter of 2012.

During the nine months ended September 30, 2012 compared to the same period in 2011, operating revenues net of purchased power and fuel expense were lower due to the impact of unfavorable 2012 winter weather conditions in PECO's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the three and nine months ended September 30, 2012 compared to the same periods in 2011 and normal weather consisted of the following:

Heating and Cooling Degree-Days	2012	2011	Normal	% Change From 2011	% Change From Normal
Three Months Ended September 30,					
Heating Degree-Days	14	18	35	(22.2)%	(60.0)%
Cooling Degree-Days	1,138	1,109	934	2.6%	21.8%
Nine Months Ended September 30,					
Heating Degree-Days	2,265	2,855	2,974	(20.7)%	(23.8)%
Cooling Degree-Days	1,572	1,603	1,282	(1.9)%	22.6%

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 nine months ended September 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 nine months ended September 30, 2012 was partially offset by additional volumes due to the extra day from the leap year.

Pricing

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011. The decrease in electric revenues net of purchased power expense as a result of pricing reflects 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.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011. The increase in operating revenues net of purchased power and fuel expense as a result of pricing reflects 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 and AEPS programs. The riders are designed to provide full and current cost recovery as well as a return. The offsetting costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Other

The decrease in other electric revenues net of purchased power expense for the three and nine months ended September 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 September 30,		Increase (Decrease)	Nine Months Ended September 30,		Increase (Decrease)
	2012	2011		2012	2011	
Operating and Maintenance Expense — Baseline	$ 170	$ 203	$ (33)	$ 506	$ 543	$ (37)
Operating and Maintenance Expense — Regulatory Required Programs(a)	29	16	13	68	54	14
Total Operating and Maintenance Expense	199	219	(20)	574	597	(23)

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

The changes in operating and maintenance expense for the three and nine months ended September 30, 2012 compared to the same periods in 2011, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ (10)	$ (25)
Storm-related costs	(23)	(31)
Pension and non-pension postretirement benefits expense	3	8
Constellation merger and integration costs	2	12
Other	(5)	(1)
	(33)	(37)
Regulatory Required Programs		
Smart Meter	1	7
Energy Efficiency	12	10
GSA	—	(2)
AEPS	—	(1)
	13	14
Decrease in operating and maintenance expense	$ (20)	$ (23)

Depreciation and Amortization Expense

The increase in depreciation and amortization expense for the three and nine months ended September 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 nine months ended September 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 nine months ended September 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 for the three and nine months ended September 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 three and nine months ended September 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 16.9% and 13.9% for the three months ended September 30, 2012 and 2011, respectively, and 28.2% and 27.5% for the nine months ended September 30, 2012 and 2011, respectively. The effective income tax rate for the three and nine months ended September 30, 2012 reflect the impact of the tax benefit received from electing to change the method of accounting for gas distribution property for the 2011 tax year. Comparatively, the effective income tax rate for the three and nine months ended September 30, 2011 include the effect of electing the safe harbor method of tax accounting for electric transmission and distribution property for the 2010 tax year. 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 September 30, 2012	Three Months Ended September 30, 2011	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)								
Residential	4,059	4,085	(0.6)%	(3.6)%	10,154	10,750	(5.5)%	(2.4)%
Small commercial & industrial	2,245	2,272	(1.2)%	(1.6)%	6,155	6,437	(4.4)%	(2.8)%
Large commercial & industrial	4,165	4,370	(4.7)%	(4.8)%	11,545	12,012	(3.9)%	(3.9)%
Public authorities & electric railroads	240	239	0.4%	0.4%	714	710	0.6%	0.6%
Total Electric Retail	10,709	10,966	(2.3)%	(3.6)%	28,568	29,909	(4.5)%	(3.0)%

Number of Electric Customers	As of September 30, 2012	2011
Residential	1,416,894	1,412,059
Small commercial & industrial	148,829	148,210
Large commercial & industrial	3,103	3,116
Public authorities & electric railroads	9,666	9,693
Total	1,578,492	1,573,078

Electric Revenue	Three Months Ended September 30, 2012	2011	% Change	Nine Months Ended September 30, 2012	2011	% Change
Retail Delivery and Sales(a)						
Residential	$ 497	$ 598	(16.9)%	$ 1,297	$ 1,542	(15.9)%
Small commercial & industrial	120	138	(13.0)%	357	472	(24.4)%
Large commercial & industrial	66	85	(22.4)%	179	261	(31.4)%
Public authorities & electric railroads	8	9	(11.1)%	24	29	(17.2)%
Total Retail	691	830	(16.7)%	1,857	2,304	(19.4)%
Other Revenue(b)	61	61	0.0%	171	183	(6.6)%
Total Electric Revenues	$ 752	$ 891	(15.6)%	$ 2,028	$ 2,487	(18.5)%

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

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

PECO Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	Three Months Ended September 30, 2012	2011	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2012	2011	% Change	Weather-Normal % Change
Retail Delivery and Sales								
Retail sales(a)	3,646	3,687	(1.1)%	(3.0)%	32,301	38,982	(17.1)%	0.5%
Transportation and other	5,796	6,190	(6.4)%	(5.3)%	19,397	21,428	(9.5)%	(8.2)%
Total Gas Deliveries	9,442	9,877	(4.4)%	(4.4)%	51,698	60,410	(14.4)%	(2.5)%

Number of Gas Customers	As of September 30, 2012	2011
Residential	452,624	448,763
Commercial & industrial	41,338	40,883
Total Retail	493,962	489,646
Transportation	900	868
Total	494,862	490,514

Gas revenue	Three Months Ended September 30, 2012	2011	% Change	Nine Months Ended September 30, 2012	2011	% Change
Retail Delivery and Sales						
Retail sales(a)	$ 49	$ 51	(3.9)%	$ 344	$ 429	(19.8)%
Transportation and other	5	4	25.0%	24	26	(7.7)%
Total Gas Deliveries	$ 54	$ 55	(1.8)%	$ 368	$ 455	(19.1)%

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

Results of Operations — BGE

	Three Months Ended September 30, 2012	2011	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2012	2011	Favorable (Unfavorable) Variance
Operating revenues	$ 720	$ 745	$ (25)	$ 2,032	$ 2,394	$ (362)
Purchased power and fuel	373	405	32	1,043	1,288	245
Revenue net of purchased power and fuel(a)	347	340	7	989	1,106	(117)
Other operating expenses						
Operating and maintenance	201	210	9	557	529	(28)
Depreciation and amortization	68	60	(8)	218	205	(13)
Taxes other than income	48	47	(1)	143	143	—
Total other operating expenses	317	317	—	918	877	(41)
Operating income	30	23	7	71	229	(158)
Other income and (deductions)						
Interest expense, net	(35)	(32)	(3)	(110)	(97)	(13)
Other, net	5	8	(3)	18	22	(4)
Total other income and (deductions)	(30)	(24)	(6)	(92)	(75)	(17)
Income (loss) before income taxes	—	(1)	1	(21)	154	(175)
Income taxes	—	(3)	(3)	(7)	55	62
Net income (loss)	—	2	(2)	(14)	99	(113)
Preference stock dividends	4	4	—	10	10	—
Net income (loss) on common stock	$ (4)	$ (2)	$ (2)	$ (24)	$ 89	$ (113)

(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 September 30, 2012 compared to the same period in 2011 was relatively consistent. The decrease in net income for the nine months ended September 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 347,200 and 297,000 at September 30, 2012 and 2011, respectively, representing 28% and 24% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 59% and 60% of BGE's retail kWh sales for the three and nine months ended September 30, 2012, respectively compared to 58% and 57% for the three and nine months ended September 30, 2011, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 132,800 and 112,200 at September 30, 2012 and 2011, respectively, representing 20% and 17% of total retail customers, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 74% and 58% of BGE's retail mmcf sales for the three and nine months ended September 30, 2012, respectively, compared to 75% and 52% for the three and nine months ended September 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	$ 6	$—	$ 6
Transmission	4	—	4
Other	(5)	2	(3)
Total increase	$ 5	$ 2	$ 7

The changes in BGE's operating revenues net of purchased power and fuel expense for the nine months ended September 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)
Commodity margin	(2)	(4)	(6)
Regulatory required programs	8	2	10
Transmission	7	—	7
Other	(11)	(4)	(15)
Total decrease	$ (80)	$(37)	$(117)

(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 nine months ended September 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 September 30,					
Heating Degree-Days	69	49	83	40.8%	(16.9)%
Cooling Degree-Days	698	677	583	3.1%	19.7%
Nine Months Ended September 30,					
Heating Degree-Days	2,344	2,890	3,019	(18.9)%	(22.4)%
Cooling Degree-Days	997	1,021	832	(2.4)%	19.8%

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 nine months ended September 30, 2012.

Commodity Margin. The commodity margin for both electric and gas revenues decreased during the nine months ended September 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.

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 nine months ended September 30, 2012 compared to the same period in 2011 was due to the recovery of higher energy efficiency program costs.

Transmission. Transmission revenues increased during the three and nine months ended September 30, 2012 compared to the same period in 2011. BGE's transmission rates are established based on a FERC-approved formula. The rates also include transmission investment incentives approved by FERC in a number of orders covering various new transmission investment projects since 2007.

Other. Other revenues decreased during the three and nine months ended September 30, 2012 compared to the same period in 2011. Other revenues, which can vary from period to period, include 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 September 30,		Increase (Decrease)	Nine Months Ended September 30,		Increase (Decrease)
	2012	2011		2012	2011	
Operating and Maintenance Expense —Baseline	$ 201	$ 210	$ (9)	$ 557	$ 529	$ 28
Operating and Maintenance Expense —Regulatory Required Programs(a)	—	—	—	—	—	—
Total Operating and Maintenance Expense	201	210	(9)	557	529	28

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

The changes in operating and maintenance expense for the three and nine months ended September 30, 2012 compared to the same periods in 2011, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Baseline		
Charitable contributions accrual(a)	$ —	$ 28
Storm costs deferral(b)	—	16
Merger transaction costs(a)	(1)	6
Pension and non-pension postretirement benefits expense	1	3
Uncollectible accounts expense	1	3
Storm-related costs(c)	(3)	(15)
Labor, other benefits, contracting and materials	(9)	(14)
Other	2	1
	(9)	28
Regulatory Required Programs		
SOS	—	—
(Decrease) increase in operating and maintenance expense	$ (9)	$ 28

(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 $58 million and $62 million of incremental costs during the three and nine months ended September 30, 2012, of which $19 million and $20 million are capital costs, respectively. This amount compares to $40 million of incremental expenses incurred during the third quarter of 2011 associated with Hurricane Irene and $14 million of incremental expenses incurred during the first quarter of 2011.

Depreciation and Amortization

The increase in depreciation and amortization expense for the three and nine months ended September 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 are fully offset in revenues above.

Taxes Other Than Income

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

Interest Expense, Net

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

Other, Net

The decrease in Other, net for the three and nine months ended September 30, 2012 compared to the same periods in 2011 was primarily due to decreased AFUDC-Equity and investment income. 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 0.0% and 300.0% for the three months ended September 30, 2012 and 2011, respectively, and 33.3% and 35.7% for the nine months ended September 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.

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BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)								
Residential	3,829	3,695	3.6%	n.m	9,693	9,971	(2.8)%	n.m
Small commercial & industrial	4,458	4,432	0.6%	n.m	12,273	12,505	(1.9)%	n.m
Large commercial & industrial	462	665	(30.5)%	n.m	1,721	1,819	(5.4)%	n.m
Public authorities & electric railroads	47	99	(52.5)%	n.m	143	308	(53.6)%	n.m
Total Electric Retail	8,796	8,891	(1.1)%	n.m	23,830	24,603	(3.1)%	n.m

Number of Electric Customers	As of September 30, 2012	As of September 30, 2011
Residential	1,115,764	1,115,279
Small commercial & industrial	119,431	118,451
Large commercial & industrial	5,448	5,550
Public authorities & electric railroads	318	326
Total	1,240,961	1,239,606

Electric Revenue	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	% Change	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	% Change
Retail Delivery and Sales(a)						
Residential	$ 400	$ 408	(2.0)%	$ 960	$ 1,157	(17.0)%
Small commercial & industrial	166	172	(3.5)%	464	500	(7.2)%
Large commercial & industrial	10	13	(23.1)%	31	40	(22.5)%
Public authorities & electric railroads	8	8	0.0%	22	22	0.0%
Total Retail	584	601	(2.8)%	1,477	1,719	(14.1)%
Other Revenue	64	60	6.7%	177	175	1.1%
Total Electric Revenues	$ 648	$ 661	(2.0)%	$ 1,654	$ 1,894	(12.7)%

(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 September 30, 2012	Three Months Ended September 30, 2011	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	% Change	Weather-Normal % Change
Retail Delivery and Sales(b)								
Retail sales	11,147	12,628	(11.7)%	n.m.	60,613	69,113	(12.3)%	n.m.
Transportation and other	2,311	3,489	(33.8)%	n.m.	12,606	13,071	(3.6)%	n.m.
Total Gas Deliveries	13,458	16,117	(16.5)%	n.m.	73,219	82,184	(10.9)%	n.m.

Number of Gas Customers	As of September 30, 2012	As of September 30, 2011
Residential	610,353	608,267
Commercial & industrial	43,978	43,979
Total	654,331	652,246

Gas revenue	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	% Change	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011	% Change
Retail Delivery and Sales						
Retail sales	$ 63	$ 66	(4.5)%	$ 335	$ 425	(21.2)%
Transportation and other(b)	9	18	(50.0)%	43	75	(42.7)%
Total Gas Deliveries	$ 72	$ 84	(14.3)%	$ 378	$ 500	(24.4)%

(b) Transportation and other gas revenue includes off-system revenue of 2,311 mmcfs ($8 million) and 3,489 mmcfs ($16 million) for the three months ended September 30, 2012 and 2011, respectively, and 12,606 mmcfs ($37 million) and 13,071 mmcfs ($68 million) for the nine months ended September 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 September 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 nine months ended September 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 $2.0 billion, $5.6 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. The Registrants' revolving credit facilities expire between December 2012 and August 2017. The bilateral facility at Generation has expirations in December 2015 and 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. During the third quarter of 2012, Exelon announced plan design changes for certain legacy Exelon and Constellation other postretirement benefit plans, requiring an interim remeasurement of the benefit obligation and assets for those plans using assumptions as of September 30, 2012. The discount rates used to calculate the other postretirement benefit plan obligations for legacy Exelon and Constellation were 3.93% and 3.72%, respectively, as of September 30, 2012. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information on the impact of the remeasurements on the financial statements.

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 September 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 3.84% and 3.93%, respectively, at September 30, 2012. The discount rate was 3.64% for legacy Constellation's pension plans and ranged from

3.66% to 3.72% for legacy Constellation's other postretirement benefit plans at September 30, 2012. Additionally, Exelon's pension and other postretirement benefit plans experienced actual asset returns of approximately 10% for the nine months ended September 30, 2012.

Based on these assumptions, Exelon has estimated the unfunded status of the pension and other postretirement benefit plans at September 30, 2012 to be $3,926 million and $2,999 million, respectively, representing a funded status percentage of 78% and 38%, respectively. The unfunded status of Exelon's pension and other postretirement benefit plans increased $1,690 million and $734 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 September 30, 2012. During the fourth quarter of 2012, Exelon will complete an optional lump sum election program for select participants in certain of its qualified pension plans, which will reduce the obligation and plan assets associated with those plans.

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

Exelon expects to contribute $77 million to its qualified pension plans in 2012, of which Generation, ComEd and PECO will contribute $46 million, $9 million and $13 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 September 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. Additionally, for Exelon's largest qualified pension plan, the contributions below reflect a funding strategy of contributing the greater of $250 million, which approximates service cost, or the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. This level funding strategy helps minimize volatility of future period required pension contributions.

	2013	2014	2015	2016	2017	Cumulative
Estimated pension contributions	$265	$280	$440	$520	$495	$ 2,000

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 $131 million, $116 million, $33 million and $13 million, respectively. This total excludes $4 million in 2012 other postretirement benefit plan payments made 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 $250 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 $610 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.
- In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The newly adopted method results in a cash tax benefit of approximately $36 million and $39 million at Exelon and PECO, respectively. Exelon currently anticipates that the IRS will issue guidance in the near future providing a safe harbor method of tax accounting for gas transmission and distribution property. See Note 4 — Regulatory Matters for discussion regarding the regulatory treatment of PECO's tax benefits from the application of the method change.

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

	Nine Months Ended September 30, 2012	2011	Variance
Net income	$ 787	$ 1,889	$(1,102)
Add (subtract):			
Non-cash operating activities(a)	4,166	3,863	303
Pension and other postretirement benefit contributions	(131)	(2,089)	1,958
Income taxes	465	532	(67)
Changes in working capital and other noncurrent assets and liabilities(b)	(1,016)	(530)	(486)
Option premiums (paid) received, net	(122)	59	(181)
Counterparty collateral received (posted), net	408	(807)	1,215
Net cash flows provided by operations	$ 4,557	$ 2,917	$ 1,640

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

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

Cash flows provided by operations for the nine months ended September 30, 2012 and 2011 by Registrant were as follows:

	Nine Months Ended September 30, 2012	2011
Exelon	$ 4,557	$2,917
Generation	3,013	2,122
ComEd	1,181	615
PECO	628	656
BGE	323	427

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 nine months ended September 30, 2012 and 2011 were as follows:

Generation

- During the nine months ended September 30, 2012 and 2011, Generation had net receipts (payments) of counterparty collateral of $315 million and $(804) million, respectively. Net receipts (payments) during the nine months ended September 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 nine months ended September 30, 2012 and 2011, Generation had net (payments) collections of approximately $(122) million and $59 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 nine months ended September 30, 2012 and 2011, Generation's accounts receivable from PECO increased (decreased) $14 and $(211) million, respectively. The decrease for the nine months ended September 30, 2011 was due to the expiration of the PECO PPA in December 2010.

ComEd

- During the nine months ended September 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 $17 million and $1 million, respectively. During the nine months ended September 30, 2012 and 2011, ComEd's payables to other energy suppliers for energy purchases decreased by $14 million and $67 million, respectively.
- During the nine months ended September 30, 2012 and 2011, ComEd received (posted) $90 million and $(6) million, respectively, of incremental cash collateral from PJM. On September 4, 2012, all $120 million of ComEd cash collateral posted with PJM was replaced with a Letter of Credit. The net incremental increase to collateral posted at PJM for the nine months ended September 30, 2012 was $30 million. ComEd's collateral posted with PJM increased during the nine months ended September 30, 2012 due to a $23 million increase for seasonal variations in usage and energy prices and 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 September 30, 2012 and 2011, ComEd had $120 million and $159 million, respectively, of collateral remaining at PJM. The decrease in the year-over-year level of total collateral held at PJM is due to overall lower market capacity and energy prices and customer load migration.

PECO

- During the nine months ended September 30, 2012 and 2011, PECO's payables to Generation for energy purchases increased (decreased) by $14 million and $(211) million, respectively, and payables to other electric and gas suppliers for energy purchases (decreased) increased by $(30) million and $72 million, respectively.

BGE

- During the nine months ended September 30, 2012 and 2011, BGE's payables to Generation for energy purchases increased by $3 million and $2 million, respectively, and payables to other electric and gas suppliers for energy purchases decreased by $27 million and $30 million, respectively.
- During the nine months ended September 30, 2012 and 2011, BGE's accrued expenses decreased by $10 million and $52 million due to the reversal of an accrued uncertain tax position, respectively.

Cash Flows from Investing Activities

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

	Nine Months Ended September 30,	
	2012	2011
Exelon	$(3,325)	$(4,031)
Generation	(2,056)	(2,421)
ComEd	(871)	(1,276)
PECO	(259)	(402)
BGE	(413)	(438)

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

	Projected Full Year 2012	Nine Months Ended September 30, 2012	2011
Exelon	$ 6,059	$ 4,145	$ 2,972
Generation(a)	3,796	2,602	1,865
ComEd(b)	1,264	896	758
PECO	434	274	321
BGE(d)	573	402	416
Other(c)	63	38	28

(a) Includes nuclear fuel.
(b) The projected capital expenditures include approximately $170 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.
(d) The projected capital expenditures include those incurred prior to the merger on March 12, 2012.

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

Generation

Approximately 34% 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. As a result of the decision to defer or cancel certain projects from the uprate program, 2012 projected capital expenditures reflect a reduction of approximately $50 million associated with the decision to defer or cancel certain projects from the uprate program. 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 estimated proceeds of approximately $388 million in the fourth quarter less cash payments of approximately $32 million to Raven Power Holdings LLC over a twelve-month period beginning in June 2014. Generation expects to incur transaction costs of approximately $20 million through the date of closing of the transaction which is expected in the fourth quarter of 2012. The sale will generate approximately $225 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 $500 million through 2013 and approximately $65 million in 2014 and subsequent years.

ComEd, PECO and BGE

Approximately 83%, 66% and 70% 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.

As a result of the October 3, 2012 ICC Rehearing Order, ComEd currently plans to defer approximately $450 million of smart meter and other infrastructure spend from the period 2012-2014 to 2015 and beyond. The 2012 projected capital expenditures reflect a reduction of approximately $65 million related to the deferral of ComEd's original investment plan filed with the ICC on January 6, 2012. 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 nine months ended September 30, 2012 and 2011 by Registrant were as follows:

	Nine Months Ended September 30, 2012	2011
Exelon	$ (548)	$ 573
Generation	(623)	(14)
ComEd	(513)	967
PECO	85	(258)
BGE	162	12

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 nine months ended September 30, 2012 and 2011 by Registrant were as follows:

	Nine Months Ended September 30, 2012	2011
Exelon	$ 1,226	$ 1,044
Generation	1,384	61
ComEd	95	225
PECO	261	271
BGE	10	95(a)

(a) Dividends on common stock for $85 million were paid to Constellation for the nine months ended September 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, paid on September 10, 2012 of $0.525 per share on Exelon's common stock.

Fourth Quarter 2012 Dividend

On October 22, 2012 the Exelon Board of Directors declared a regular quarterly dividend, payable on December 10, 2012 of $0.525 per share on Exelon's common stock.

Short-Term Borrowings

During the nine months ended September 30, 2012, Exelon repaid $146 million of outstanding commercial paper, ComEd issued $35 million of commercial paper and Generation repaid $25 million in short-term notes payable. During the nine months ended September 30, 2011, Exelon issued $389 million of commercial paper and Generation issued $73 million of commercial paper.

Contributions from Parent/Member

During the nine months ended September 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. During the nine months ended September 30, 2011, Exelon contributed $30 million and $18 million to Generation and PECO, respectively.

Other

For the nine months ended September 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 $9.8 billion in aggregate total commitments of which $7.5 billion was available as of September 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 third 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 September 30, 2012, it would have been required to provide incremental collateral of $2.0 billion, which is well within its current available credit facility capacities of $3.5 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 September 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 $844 million, which takes into account commercial paper borrowings as of September 30, 2012. If PECO lost its investment grade credit rating as of September 30, 2012, it would have been required to provide collateral of $1 million pursuant to PJM's credit policy and could have been required to provide collateral of $30 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 September 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 $51 million related to its natural gas procurement contracts, which, in the aggregate, is well within BGE's current available credit facility capacity of $499 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 September 30, 2012:

Commercial Paper Programs

Commercial Paper Issuer	Maximum Program Size	Outstanding Commercial Paper at September 30, 2012	Average Interest Rate on Commercial Paper Borrowings for the nine months ended September 30, 2012
Exelon Corporate(a)	$ 500	$ 15	0.47%
Generation	5,600	—	0.45%
ComEd	1,000	35	0.50%
PECO	600	—	—
BGE	400	—	0.43%

(a) The Exelon $1.5 billion revolver is 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 September 30, 2012 Actual	Available Capacity at September 30, 2012 To Support Additional Commercial Paper	Average Interest Rate on Facility Borrowings for the Nine Months Ended September 30, 2012
Exelon Corporate(b)	Syndicated Revolvers	$ 2,000	$ —	$ 18	$1,982	$ 498	—
Generation	Syndicated Revolver	5,300	—	1,751	3,549	3,549	—
Generation	Bilateral	300	—	299	1	1	—
ComEd	Syndicated Revolver	1,000	—	121	879	844	—
PECO	Syndicated Revolver	600	—	1	599	599	—
BGE	Syndicated Revolver	600	—	1	599	499	—

(a) Excludes $118 million of credit facility agreements arranged with minority and community banks at Generation, ComEd and PECO. These facilities, which expired and were replaced in October 2012, were 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 is not currently used to support the Exelon commercial paper program.

On October 19, 2012, Generation, ComEd and PECO replaced their expiring minority and community bank credit facility agreements with new minority and community bank credit facility agreements in the amounts of $50 million, $34 million and $34 million, respectively, and BGE entered into a minority and community bank credit facility in the amount of $5 million. These facilities, which expire in October 2013, are solely utilized to issue letters of credit.

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 September 30, 2012, the outstanding loan balance was $117 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 September 30, 2012, the outstanding loan balance was $75 million.

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. Costs incurred to amend and extend the facilities for ComEd were not material.

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 fee varies depending upon ComEd’s credit rating. The credit agreement also requires ComEd to pay a facility fee based upon the aggregate commitments under the agreement.

On August 10, 2012, Exelon Corporate, Generation, PECO and BGE amended and extended their respective unsecured syndicated revolving credit facilities, with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively, through August 10, 2017. Under these facilities Exelon Corporate, Generation, PECO and BGE may issue letters of credit in the aggregate of up to $200 million, $3.5 billion, $300 million and $600 million, respectively. Each credit facility permits the applicable borrower to request extensions for up to two additional one-year periods. Each credit facility also allows Exelon Corporate, Generation, PECO and BGE to request increases in aggregate commitments up to an additional $250 million, $1.0 billion, $250 million and $100 million, respectively. Any such extensions or increases are subject to the approval of the lenders party to the credit facilities in their sole discretion. Costs incurred to amend and extend the facilities for Exelon Corporate, Generation, PECO and BGE were not material.

The amended credit facilities updated the credit ratings-based pricing grids used to determine the facility fee and interest rates for borrowings under each facility and reflect current market pricing and maturities of five years from the close of the transactions. Borrowings under each credit agreement bear interest at a rate selected by the borrower based upon the prime rate or upon a LIBOR-based rate. Exelon Corporate, Generation, PECO and BGE had adders of 27.5, 7.5, 0.0 and 7.5 basis points for prime-based borrowings and 127.5, 107.5, 100.0 and 107.5 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The covenants in each of Exelon Corporate, Generation, PECO and BGE’s extended facilities are substantially consistent with existing covenants, with the exception of the BGE facility, in which a debt to capitalization financial covenant was replaced with an interest coverage ratio financial covenant.

Each revolving credit agreement for Exelon, Generation, ComEd, PECO and BGE requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve- month period ended on the last day of any quarter. The following table summarizes the minimum thresholds reflected in the credit agreements for the nine months ended September 30, 2012:

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

At September 30, 2012, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	9.96	19.22	6.18	7.99	5.51

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.

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 nine months ended September 30, 2012, in addition to the net contribution or borrowing as of September 30, 2012, are presented in the following table:

Contributed (borrowed) as of September 30, 2012	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Generation	$ —	$ 258	$ —
PECO	309	—	77
BSC	—	206	(77)
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 September 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 September 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 $1.6 billion available in long-term debt financing authority from the PAPUC and BGE had $1.8 billion available in long-term financing authority from the MDPSC. On October 24, 2012, the PAPUC approved PECO's application for long-term financing authority for $2.5 billion, which will be effective over a three-year period from January 1, 2013 through December 31, 2015.

As of September 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. On October 26, 2012, BGE filed an application with FERC for renewal of its short-term financing authority through December 31, 2014. BGE expects resolution of the application before the end of the year. 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 September 30, 2012, the percentage of expected generation hedged was 98%-101%, 87%-90%, 55%-58% and 20%-23% for 2012, 2013, 2014 and 2015, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity 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 September 30, 2012 market conditions and hedged position would be a decrease in pre-tax net income of approximately $10 million, $110 million and $500 million, respectively, for 2012, 2013 and 2014. 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 4,352 GWhs and 9,981 GWhs for the three and nine months ended September 30, 2012, respectively, and 1,679 GWhs and 4,508 GWhs for the three and nine months ended September 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 nine months ended September 30, 2012 resulted in pre-tax gains of $10 million due to net mark-to-market gains of $69 million and realized losses of $59 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 $2.9 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 nine months ended September 30, 2012 of $5,491 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 57% 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).

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 September 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 the 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 September 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	48	—	—	33	81
Reclassification to realized at settlement of contracts recorded in results of operations	302	—	—	—	302
Ineffective portion recognized in income(b)	(5)	—	—	—	(5)
Reclassification to realized at settlement from accumulated OCI(c)	(1,005)	—	—	455	(550)
Effective portion of changes in fair value — recorded in OCI(d)	719	—	—	(146)	573
Changes in fair value — energy derivatives(e)	—	378	—	(342)	36
Changes in collateral	(313)	—	—	—	(313)
Changes in net option premium paid/(received)	122	—	—	—	122
Other income statement reclassifications(f)	(119)	—	—	—	(119)
Intercompany Elimination of Existing Derivative Contracts with Constellation	(103)	—	—	—	(103)
Other balance sheet reclassifications	(3)	—	—	—	(3)
Total mark-to-market energy contract net assets (liabilities) at September 30, 2012(a)	$ 1,431	$ (422)	$ —	$ —	$ 1,009

(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 $457 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 nine months ended September 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 nine months ended September 30, 2012.
(e) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of September 30, 2012, ComEd recorded a $422 million regulatory asset related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. As of September 30, 2012, this included $86 million change in fair value and $427 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 September 30, 2012, ComEd also recorded a $33 million change in fair value and $2 million due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.
(f) Includes $119 million of option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations for the nine months ended September 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, offset by $520 million of losses on commodity derivative positions.

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)	$ 10	$ 2	$ (87)	$ (41)	$11	$ 2	$ (103)
Prices provided by external sources (Level 2)	116	317	331	103	21	—	888
Prices based on model or other valuation methods (Level 3)(c)	—	76	60	42	23	23	224
Total	$126	$395	$304	$104	$55	$ 25	$ 1,009

(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 $193 million at September 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)	$ 10	$ 2	$ (87)	$ (41)	$11	$ 2	$ (103)
Prices provided by external sources (Level 2)	116	317	331	103	21	—	888
Prices based on model or other valuation methods (Level 3)	161	290	76	57	36	26	646
Total	$287	$609	$320	$119	$68	$ 28	$ 1,431

(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 $352 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 $193 million at September 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)	$(161)	$(214)	$(16)	$(15)	$(13)	$ (3)	$ (422)

(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.

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 September 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 $53 million, $53 million and $11 million, respectively. See Note 21 of the Exelon 2011 Form 10-K for further information.

Rating as of September 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	$ 1,968	$ 492	$ 1,476	—	$ —
Non-investment grade	46	25	21	—	—
No external ratings					
Internally rated — investment grade	501	16	485	1	267
Internally rated — non-investment grade	90	2	88	—	—
Total	$ 2,605	$ 535	$ 2,070	1	$ 267

	Maturity of Credit Risk Exposure			
Rating as of September 30, 2012	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 1,472	$ 374	$ 122	$ 1,968
Non-investment grade	34	12	—	46
No external ratings				
Internally rated — investment grade	291	187	23	501
Internally rated — non-investment grade	90	—	—	90
Total	$ 1,887	$ 573	$ 145	$ 2,605

Net Credit Exposure by Type of Counterparty	As of September 30, 2012
Investor-owned utilities, marketers and power producers	$ 902
Energy cooperatives and municipalities	710
Financial institutions	386
Other	72
Total	$ 2,070

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 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.

As of September 30, 2012, Generation had $415 million cash collateral deposit payments being held by counterparties and Generation was holding $607 million of cash collateral deposits received from counterparties, of which $193 million in net cash collateral deposits was offset against mark-to-market assets and liabilities. As of September 30, 2012, $1 million of cash collateral posted 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 September 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 $19 million in the form of cash and letters of credit for both annual and long-term renewable energy contracts.

PECO

As of September 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 September 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 September 30, 2012, included a $678 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 $814 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 September 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 $396 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 approximately $ 2 million decrease in Exelon Consolidated pre-tax income for the nine months ended September 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 September 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 $382 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

Item 4. Controls and Procedures

During the third quarter of 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 September 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 third quarter of 2012 that have materially affected, or are reasonably likely to materially affect, any of Exelon's, Generation's, ComEd's, PECO's and BGE's internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see (a) ITEM 3. LEGAL PROCEEDINGS of 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

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

Exhibit No.	Description
2.1	Purchase Agreement dated as of August 8, 2012 by and between Constellation Power Source Generation, Inc. and Raven Power Holdings, LLC
4.1	Form of 2.80% Senior Note due 2022. (File 1-1910, Form 8-K dated August 17, 2012, Exhibit 4.1)
4.2	Supplemental Indenture dated as of September 10, 2012 from PECO Energy Company to BNP Paribas Securities, J.P. Morgan Securities LLC and U.S. Bancorp Investments, Inc., as representatives of the several underwriters named therein. (File No. 000-16844, Form 8-K dated September 17, 2012, Exhibit 4-1)
4.3	Supplemental Indenture dated as of September 17, 2012 from Commonwealth Edison Company to BNY Mellon Trust Company of Illinois, as trustee, and D.G. Donovan, as co-trustee. (File No. 1-1839, Form 8-K dated October 1, 2012, Exhibit 4-1)
101.INS*	XBRL Instance
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation
101.DEF*	XBRL Taxonomy Extension Definition
101.LAB*	XBRL Taxonomy Extension Labels
101.PRE*	XBRL Taxonomy Extension Presentation

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* 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 September 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 September 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

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
Christopher M. Crane
President and Chief Executive Officer
(Principal Executive Officer)

/s/ JONATHAN W. THAYER
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)

November 7, 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
Christopher M. Crane
President
(Principal Executive Officer)

/s/ ANDREW L. GOOD
Andrew L. Good
Chief Financial Officer
(Principal Financial Officer)

/s/ ROBERT M. AIKEN
Robert M. Aiken
Chief Accounting Officer
(Principal Accounting Officer)

November 7, 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
Anne R. Pramaggiore
President and Chief Executive Officer
(Principal Executive Officer)

/s/ JOSEPH R. TRPIK, JR.
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)

November 7, 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.

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)	

November 7, 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)	

November 7, 2012

Exhibit 2.1

EXECUTION VERSION

PURCHASE AND SALE AGREEMENT

by and between

CONSTELLATION POWER SOURCE GENERATION, INC.

as Seller,

and

RAVEN POWER HOLDINGS LLC

as Buyer,

dated as of August 8, 2012

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EXECUTION VERSION

PURCHASE AND SALE AGREEMENT

This PURCHASE AND SALE AGREEMENT (this "***Agreement***"), is dated as of August 8, 2012, by and between **Constellation Power Source Generation, Inc.**, a Maryland corporation ("***Seller***"), and **Raven Power Holdings LLC**, a Delaware limited liability company ("***Buyer***").

W I T N E S S E T H:

WHEREAS, Seller owns each of the following predominantly coal-fired electric generating facilities, and certain facilities and other assets associated therewith and ancillary thereto, (i) Brandon Shores, located in Pasadena, Maryland (as further defined herein, the "***Brandon Shores Facility***"), (ii) H.A. Wagner, located in Pasadena, Maryland (as further defined herein, the "***H.A. Wagner Facility***") and (iii) C.P. Crane, located in Middle River, Maryland (as further defined herein, the "***C.P. Crane Facility***" and together with the Brandon Shores Facility and the H.A. Wagner Facility, the "***Facilities***");

WHEREAS, pursuant to the terms of that certain Final Judgment, dated May 23, 2012 (the "***Final Judgment***"), in the case captioned *United States of America v. Exelon Corporation and Constellation Energy Group, Inc.*, Case N. 11-cv-02276, United States District Court for the District of Columbia, Seller, an indirect wholly-owned subsidiary of Exelon Corporation, is required to divest the Facilities subject to certain limitations as set forth in the Final Judgment;

WHEREAS, the divestiture and operation of the Facilities are subject to the order issued by the Federal Energy Regulatory Commission on March 9, 2012 in Docket Nos. EC11-83-000 and EC11-83-001 (the "***FERC Order***") and Order No. 84698 issued by the Public Service Commission of Maryland on February 17, 2012 in the matter captioned *In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Inc.*;

WHEREAS, Buyer desires to purchase and assume, and Seller desires to sell and assign, the Acquired Assets (as defined in Section 2.1 below) and certain associated liabilities upon the Closing as more fully described herein, upon the terms and conditions set forth in this Agreement;

WHEREAS, Buyer has required that Exelon Generation Company, LLC ("***Guarantor***") provide the guaranty set forth in Article XI as an inducement for Buyer to enter into this Agreement; and

NOW, THEREFORE, in consideration of the premises and the mutual representations, warranties, covenants and agreements in this Agreement, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Seller and Buyer (and, with respect to Sections 1.2, 10.1, 10.2, 10.3, 10.6, 10.8, 10.10, 10.13 and Article XI, the Guarantor) hereby agree as follows:

ARTICLE I
DEFINITIONS AND CONSTRUCTION

Section 1.1 Definitions. As used in this Agreement, the following capitalized terms have the meanings set forth below:

"***500 MW Commitment***" means the commitment by Seller and its Affiliates to sell 500 MW per hour of around the clock baseload energy for delivery into the PJM 5004/05 submarket, on or prior to December 31, 2014, as required by the FERC Order.

"***Acquired Assets***" has the meaning given to it in Section 2.1.

"***Acquired Entity***" has the meaning given to it in Section 2.1(j).

"***Adjustment Amount***" has the meaning given to it in Section 2.9(c).

"***Adjustment Statements***" has the meaning given to it in Section 2.9(c).

"***Affiliate***" means, with respect to any Person, any other Person that directly or indirectly through one or more intermediaries, controls, is controlled by or is under common control with such Person. For purposes of this definition, "control" of a Person means the power, direct or indirect, to direct or cause the direction of the management and policies of such Person whether through ownership of voting securities or ownership interests, by Contract or otherwise.

"***Agreement***" has the meaning given to it in the introduction to this Agreement.

"***Ancillary Agreements***" means the Closing Certificates, the Deeds, the Bills of Sale, the Assignment and Assumption Agreements, the Transition Services Agreement, the Solar Facility License Agreement and the other documents and agreements to be delivered pursuant to this Agreement.

"***Applicable Clearing Price***" has the meaning given to it in Section 5.26(b).

"***Assigned Contracts***" has the meaning set forth in Section 2.1(f).

"***Assignment and Assumption Agreement***" means one or more agreements by which Seller and/or its Affiliates, as applicable, shall assign to Buyer (or its designee) the Acquired Assets and Buyer (or its designee) shall assume the Assumed Liabilities, in substantially the form attached hereto as **Exhibit A**.

"***Assumed Liabilities***" has the meaning given to it in Section 2.3.

"***Balance Sheet***" has the meaning given to it in Section 3.23(a).

"***Base Purchase Price***" means $330,000,000.

"***BGE***" means Baltimore Gas and Electric Company.

"***Bill of Sale***" means one or more bills of sale by which the title to the Acquired Assets comprised of personal property shall be conveyed by Seller and/or its Affiliates, as applicable, to Buyer or its designee, substantially in the form attached hereto as **Exhibit B**.

"***Books and Records***" means books, records, files, documents, Contracts, title and real estate documents, drawings, diagrams, data, accounting and Tax records, marketing and other such studies, instruments, papers, journals, deeds, licenses, present and former supplier, contractor and subcontractor lists, supplier design interface information, computer files and programs (other than Seller's enterprise-wide computer programs, except to the extent included as an Assigned Contract), environmental studies and reports prepared by third parties, construction reports, annual operating plans, monthly operating reports, operating logs, operations and maintenance records, purchase orders, safety and maintenance manuals, incident reports, injury reports, engineering design plans, blue prints and as-built plans, drawings, specifications, test reports, quality documentation and reports, motor vehicle or equipment records, equipment repair, maintenance and service records, hazardous waste disposal records, training records, manuals specific to or necessary for the operation of any of the Facilities or the Acquired Assets, procedures and similar items; in each case, relating to any of the Acquired Assets and in the possession of Seller or its Affiliates and any other documents or records required to be divested, transferred or assigned to the purchaser of the Facilities by the Final Judgment or FERC Order; provided, however, that any such data currently contained in computer systems shall be provided in electronic format as either fixed form or character delimited data and shall include record descriptions, to the extent the computer systems of Buyer and Seller are compatible in allowing such data provision; in each case excluding (a) documents relating to the sale process of the Facilities, (b) price curves, power curves or other proprietary information of Seller, to the extent not primarily related to the Acquired Assets and (c) income or franchise Tax Returns of Seller or any of its Affiliates.

"***Brandon Shores Facility***" means the approximately 1,273 megawatt coal-fired generating facility located in Pasadena, Maryland, all other improvements relating to the ownership, operation and maintenance of said generating plant and associated equipment and all associated expansion, conversion and development rights related to said generating facility and, to the extent required to be divested, transferred or assigned to the purchaser of the Facilities by the Final Order, any other assets relating thereto.

"***Budgeted Capital Expenditures***" means the budgeted amount of capital expenditures of Seller for the projects set forth on **Schedule 1.1-BCE** with respect to the Interim Period, subject to daily proration or other reasonable allocation method.

"***Burdensome Condition***" means any requirement imposed on Buyer, its Affiliates or any of the Acquired Assets by a Governmental Authority in connection with a Seller's Required Consent or a Buyer's Required Consent that (a) restricts in any material respect the ability of Buyer or any of its Affiliates to own or operate the Acquired Assets, or (b) requires Buyer or any of its Affiliates to take (or refrain from taking) any action with respect to any of their respective property or assets (including the Acquired Assets) that could reasonably be expected to materially adversely affect any of the Facilities, the Acquired Assets, the Assumed Liabilities, Buyer or any of its Affiliates.

"***Business Day***" means a day other than Saturday, Sunday or any day on which banks located in the State of New York are authorized or obligated to close.

"***Buyer***" has the meaning given to it in the introduction to this Agreement.

"***Buyer Adjustment Statement***" has the meaning given to it in Section 2.9(c).

"***Buyer Indemnified Parties***" has the meaning given to it in Section 9.1(a).

"***Buyer's Observers***" has the meaning given to it in Section 5.3(b).

"***Buyer's Required Consents***" means (a) those consents, approvals, orders or authorizations of, or registrations, declarations or filings with, Governmental Authorities or Persons that are required by applicable Law, Permit or Contract in order for Buyer to consummate the transactions contemplated by this Agreement and are set forth on **Schedule 1.1-BRC** attached hereto and (b) the approval of, or consent to, (i) the transactions contemplated by this Agreement and (ii) Buyer's participation in such transactions, in each case by the United States Department of Justice or, if necessary, the court overseeing the Final Judgment.

"***Capital Commitments***" means all binding contractual commitments to make capital expenditures relating to any of the Acquired Assets, the Facilities or the Sites incurred by Seller or any of its Affiliates during the Interim Period that extend beyond the Closing Date or could become an Assumed Liability, whether or not relating to the Project Capital Expenditures.

"***Capital Expenditures Adjustment Amount***" means the Project Capital Expenditures minus the Budgeted Capital Expenditures, which amount may be a positive or a negative number.

"***Capital Expenditures True Up***" has the meaning given to it in Section 2.9(b).

"***Cash***" means cash and Cash equivalents (including marketable securities and short term investments) calculated in accordance with GAAP.

"***Casualty Cost***" has the meaning given to it in Section 5.13.

"***Casualty Loss***" has the meaning given to it in Section 5.13.

"***CERCLA***" means the Comprehensive Environmental Response, Compensation and Liability Act of 1980, 42 U.S.C. §9601, et seq., as amended.

"***Claim***" means any demand, complaint, suit, claim, charge, action, investigation, legal proceeding (whether at law or in equity), order, ruling or arbitration.

"***Claiming Party***" has the meaning given to it in Section 9.4(a).

"***Closing***" means the closing of the transactions contemplated by this Agreement, as provided for in Section 2.6.

"***Closing Certificates***" means the officer's certificates referenced in Section 6.3 and Section 7.3.

"***Closing Date***" means the date on which Closing occurs.

"***Closing Purchase Price***" has the meaning given to it in Section 2.5.

"***Closing Working Capital Amount***" has the meaning given to it in Section 2.9(c).

"***Coal Support Obligations***" means the following Support Obligations: Guaranty Agreement between Constellation Energy Group, Inc. and Alpha Coal Sales Co., LLC, dated July 22, 2011, Guaranty Agreement between Exelon Corporation and Consol Pennsylvania Coal Company, LLC, dated June 27, 2012, Guaranty Agreement between Constellation Energy Commodities Group, Inc., Arch Coal Sales Company, Inc. and Arch Energy Resources, LLC, dated March 19, 2012, Guaranty Agreement between Constellation Energy Group, Inc. and Patriot Coal Sales, LLC, dated April 7, 2011 and Guaranty Agreement between Constellation Energy Group, Inc. and COALTRADE, LLC, COALSALES II, LLC, Peabody COALTRADE Australia Pty Ltd., COALSALES, LLC, COALTRADE International, LLC and Peabody COALTRADE International Limited, LLC, dated August 20, 2010.

"***Code***" means the Internal Revenue Code of 1986, as amended from time to time.

"***Condemnation Value***" has the meaning given to it in Section 5.14.

"***Confidential Information***" has the meaning given to it or the term "Evaluation Material" in the Confidentiality Agreement.

"***Confidentiality Agreement***" means the Confidentiality Agreement dated April 13, 2012 between Seller and Riverstone Investment Group LLC.

"***Contract***" means any legally binding contract, lease, license, evidence of Indebtedness, mortgage, indenture, purchase order, binding bid, letter of credit, security agreement or other legally binding arrangement, but shall exclude Permits.

"***C.P. Crane Facility***" means the approximately 399 megawatt coal, oil and/or natural gas- fired generation facility located in Middle River, Maryland, all other improvements relating to the ownership, operation and maintenance of said generating plant and associated equipment and all associated expansion, conversion and development rights related to said generating facility and, to the extent required to be divested, transferred or assigned to the purchaser of the Facilities by the Final Order, any other assets relating thereto.

"***Deductible Amount***" means 1.5% of the Base Purchase Price.

"***Deeds***" mean the form of deeds by which the Owned Real Property shall be conveyed to Buyer, substantially in the forms attached hereto as **Exhibits C, D and E**.

"***Designated Representations***" means the representations and warranties contained in Section 3.1 (Organization), Section 3.2 (Acquired Entity), Section 3.3 (Authorization of Transaction), Section 3.5(a) (Title to Acquired Assets) (other than to the extent such representation and warranty relates to real property), Section 3.20 (Brokers), Section 3.21 (No Indebtedness), Section 4.1 (Organization), Section 4.2 (Authorization of Transaction) and Section 4.9 (Brokers).

"***Division***" means the Antitrust Division of the United States Department of Justice.

“***Effective Date***” means the date of this Agreement.

“***Emission Allowances***” means, collectively, NO_x Allowances and SO_2 Allowances.

“***Environmental Claim***” means any Claim or Loss arising out of or related to any Environmental Law or Environmental Permit, whether occurring before or after the Effective Date or the Closing Date.

“***Environmental Condition***” means the presence of Hazardous Substances at, on, in, over, from or under the Sites (including the air, soil or groundwater thereof), including any migration of such Hazardous Substances from the Sites.

“***Environmental Indemnity Claim***” has the meaning given to it in Section 9.5.

“***Environmental Permits***” has the meaning given to it in Section 3.15(a).

“***Environmental Laws***” means all federal, state and local laws, regulations, rules, ordinances, codes, common law decrees, judgments, directives, or judicial or administrative orders relating to pollution or protection of the environment, natural resources or human health and safety, including laws relating to Releases or threatened Releases of Hazardous Substances (including to air, surface water, groundwater, land, surface and subsurface strata) or otherwise relating to the manufacture, processing, distribution, use, treatment, storage, disposal, arrangement for disposal, Release, transport or handling of Hazardous Substances, laws relating to record keeping, notification, disclosure and reporting requirements respecting Hazardous Substances, and Laws relating to the management, use, restoration, or compensation for use of or damage to natural resources.

“***ERISA***” means the Employee Retirement Income Security Act of 1974, as amended.

“***ERISA Affiliate***” means any entity, trade or business that is a member of a group described in Section 414(b) or (c) of the Code or Section 400l(b)(l) of ERISA that includes Seller, or that is a member of the same “controlled group” as Seller pursuant to Section 4001(a)(14) of ERISA.

“***Estimated Capital Expenditures Adjustment Amount***” has the meaning given to it in Section 2.5(c).

“***Estimated Closing Statement***” has the meaning given to it in Section 2.9(a).

“***Estimated Fuel Inventory Amount***” has the meaning given to it in Section 2.5(d).

“***Estimated Proration Amount***” has the meaning given to it in Section 2.10(a).

“***Estimated Working Capital Amount***” has the meaning given to it in Section 2.9(a).

“***Excluded Assets***” has the meaning given to it in Section 2.2.

“***Excluded Liabilities***” has the meaning given to it in Section 2.4.

“***Exelon***” means Exelon Corporation.

“***Facilities***” has the meaning given to it in the recitals to this Agreement.

“***FERC Order***” has the meaning given to it in the Recitals.

“***Final Judgment***” has the meaning given to it in the Recitals.

“***Final Remainder Capacity***” has the meaning given to it in Section 5.26(b).

“***FIRPTA Affidavit***” means the affidavit to be delivered at Closing pursuant to Section 1445(b)(2) of the Code and the Treasury Regulations promulgated thereunder, to establish that Seller is not a “foreign person” within the meaning of that Section.

“***First Auction***” has the meaning given to it in Section 5.26(a).

“***First Remainder Uncleared Capacity***” has the meaning given to it in Section 5.26(b).

“***Fuel Inventory***” means coal (including treated coal), lignite, limestone, petroleum coke, fuel oil, natural gas or alternative fuel inventories which exclusively relate to the use, ownership, operation or maintenance of any of the Facilities, the Acquired Assets or any part thereof as determined in accordance with **Schedule 1.1-IA**. Fuel Inventory does not include any inventories relating to the use, ownership, operation or maintenance of the Excluded Assets.

“***Fuel Inventory Adjustment Amount***” has the meaning given to it in Section 2.9(c).

“***Fuel Inventory Amount***” means an amount equal to the value of the Fuel Inventory, which shall be (a) determined in accordance with **Schedule 1.1-IA** and (b) measured during the period beginning ten (10) Business Days before the Closing Date and ending five (5) Business Days after the Closing Date by one or more mutually agreed Persons that are not Affiliates of Buyer or Seller.

“***GAAP***” means generally accepted accounting principles in the United States of America applied on a basis consistent with Seller’s past practice relating to the business and operations of the Acquired Assets.

“***Good Utility Practice***” means any of the practices, methods, standards, procedures and acts engaged in or approved by a significant portion of the merchant generating industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result in a manner consistent with good business practices, Law, reliability, safety, and expedition. “Good Utility Practice” is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region.

“***Governmental Authority***” means any government, court, tribunal, arbitrator, authority, agency, commission, official or other instrumentality of the United States or any state, county, city or other political subdivision or similar governing entity, and including any governmental, quasi-governmental or non-governmental body administering, regulating or having general oversight over natural gas, electricity, power or other markets.

“***Guaranteed Obligations***” has the meaning given to it in Section 11.1.

“***Guarantor***” has the meaning give to it in the recitals to this Agreement.

“***Guaranty Expiration Date***” has the meaning given to it in Section 11.1.

“***H.A. Wagner Facility***” means the approximately 977 megawatt coal, oil and/or natural gas-fired generation facility located in Pasadena, Maryland, all other improvements relating to the ownership, operation and maintenance of said generating plant and associated equipment and all associated expansion, conversion and development rights related to said generating facility and, to the extent required to be divested, transferred or assigned to the purchaser of the Facilities by the Final Order, any other assets relating thereto.

“***Hazardous Substances***” means (a) any petrochemical or petroleum products, oil or coal ash, radioactive materials, radon gas, asbestos in any form that is or could become friable, urea formaldehyde foam insulation and transformers or other equipment that contain dielectric fluid which may contain levels of polychlorinated biphenyls; (b) any chemicals, materials or substances defined as or included in the definition of “hazardous substances,” “hazardous wastes,” “hazardous materials,” “restricted hazardous materials,” “extremely hazardous substances,” “toxic substances,” “contaminants” or “pollutants” or words of similar meaning and regulatory effect; or (c) any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

“***Hiring Time***” has the meaning set forth in Section 5.9(a).

“***Hold Separate Order***” means the Hold Separate Stipulation entered into between Seller and Division dated May 23, 2012, in the case captioned United States of America v. Exelon Corporation and Constellation Energy Group, Inc., Case N. 11-cv-02276, United States District Court for the District of Columbia.

“***Indebtedness***” means any of the following: (a) any indebtedness for borrowed money; (b) any obligations evidenced by bonds, debentures, notes or other similar instruments; (c) any obligations to pay the deferred purchase price of property or services, except trade accounts payable and other current liabilities arising in the ordinary course of business consistent with past practices; (d) any obligations as lessee under capitalized leases; (e) any obligations, contingent or otherwise, under acceptance, letters of credit or similar facilities; (f) any guaranty of any of the foregoing (except in the cases of (e) and (f), for Support Obligations); and (g) any accrued interest, prepayment penalties, premiums, late charges, penalties and collection fees relating to any of such indebtedness.

“***Indemnified Party***” means a Person entitled to be indemnified by another Person pursuant to the terms of this Agreement.

“***Indemnifying Party***” means a Person required to indemnify another Person pursuant to the terms of this Agreement.

"***Independent Accountant***" means Grant Thornton LLP or such other nationally recognized firm of independent public accountants as may be mutually agreed by Buyer and Seller.

"***Independent Appraiser***" has the meaning given to it in Section 2.11.

"***Intellectual Property***" means the following intellectual property rights, both statutory and common law rights, if applicable: (a) copyrights, registrations and applications for registration thereof, (b) trademarks, service marks, trade names, slogans, domain names, logos, trade dress, and registrations and applications for registrations thereof, (c) patents, as well as any reissued and reexamined patents and extensions corresponding to the patents, and any patent applications, as well as any related continuation, continuation in part and divisional applications and patents issuing therefrom and (d) trade secrets and confidential information, including ideas, designs, concepts, compilations of information, methods, techniques, procedures, processes and other know-how, whether or not patentable.

"***Interim Period***" means the period commencing on the date of this Agreement and ending at the time of the Closing on the Closing Date.

"***Knowledge***" means, when used in a particular representation in this Agreement, with respect to Seller, the actual knowledge of the persons identified on **Schedule 1.1-K**, after reasonable inquiry of those persons employed by Seller whom such individuals reasonably believe in good faith to be generally responsible for the information, facts or events with respect to which such representation applies.

"***Laws***" means all laws, rules, statutes, regulations, codes, injunctions, judgments, orders (including the Final Judgment and FERC Order), decrees, rulings, interpretations, constitutions, ordinances, common law, or treaties, of any Governmental Authority or any foreign, international, or multinational government or administration and related agencies.

"***Lease***" and "***Leases***" have the meanings given to them in Section 3.16(b).

"***Leased Real Property***" has the meaning given to it in Section 3.16(b).

"***Liability***" or "***Liabilities***" means any liability or obligation (whether billed or unbilled, known or unknown, whether asserted or unasserted, whether absolute or contingent, whether accrued or unaccrued, whether liquidated or unliquidated and whether due or to become due).

"***Lien***" means any mortgage, pledge, lien, security interest, charge, claim, equitable interest, option, encumbrance, easement, title imperfection, restriction on transfer, conditional sale or other title retention device or arrangement (including a capital lease), transfer for security for the payment of any Indebtedness, whether relating to any property or right or the income or profits therefrom.

"***Loss***" means any and all judgments, losses, liabilities, amounts paid in settlement, damages, fines, penalties, deficiencies, costs, Taxes, obligations and expenses (including interest, court costs, reasonable fees of attorneys, accountants and other experts and other reasonable expenses of litigation or other proceedings). For all purposes in this Agreement, the term "Losses" does not include any Non-reimbursable Damages.

"***Lot 15***" means the landfill located at the location described on **Schedule 1.1-L15**.

"***Lot 15 Solid Waste Permit***" means the refuse disposal permit for Lot 15 for which Seller commenced an application with the Phase I and Phase II submissions to the Maryland Department of Environment in April and November 2011, respectively.

"***Maryland Clean Coal***" has the meaning given to it in the Maryland Clean Coal, a Business of Constellation Energy Group, Inc., Combined Financial Statements for the years ended December 31, 2011, 2010 and 2009, audited by PricewaterhouseCoopers LLP.

"***Material Adverse Effect***" means any occurrence, condition, change, development, event or effect that is materially adverse to the business, Assets, liabilities, operation or condition (physical, financial or otherwise) of the Facilities, the Acquired Assets or the Assumed Liabilities, taken as a whole in the aggregate, except for (a) any change or effect resulting from changes in the international, national, regional or local wholesale or retail markets for electric power, (b) any change or effect resulting from the international, national, regional or local markets for fuel used at the Facilities, (c) any change or effect resulting from changes in the North American, national, regional or local transmission system, (d) any change in applicable Laws, (e) any change or effect resulting from a change in GAAP, (f) any change or effect resulting from the announcement or pendency of the transactions contemplated by this Agreement, (g) any change or effect in regulatory or political conditions, including any acts of war or terrorism, (h) any change or effect resulting from changes in the national, regional or local economic or financial conditions or securities markets, (i) strikes, work stoppages or other labor disturbances other than those involving only the Facilities workforce, and (j) increases in costs of commodities or supplies, including fuel (provided, that in the case of clauses (a), (b), (c), (d), (e), (g), (h) and (j), such occurrence, condition, change, development, event or effect shall only be excluded to the extent it does not have a disproportionate adverse effect on one or more of the Facilities, as compared to other Persons engaged in the coal fired power generation business).

"***Material Contracts***" has the meaning given to it in Section 3.12(a).

"***Multiemployer Plan***" means any "multiemployer plan" within the meaning of Section 4001(a)(3) of ERISA previously or currently covering any Seller Employees or Off-Site Employees.

"***Non-reimbursable Damages***" has the meaning given to it in Section 9.3(b).

"***Notice of Objection***" has the meaning given to it in Section 2.9(d).

"***NO_x***" means oxides of nitrogen.

"***NO_x Allowance***" means an allowance or authorization used to comply with an NO_x Budget Program, including: (a) an Allowance as that term is defined in Md. Environment Code Ann. § 2-1001(c)(2); (b) an NO_x Ozone Season Allowance as that term is defined in COMAR 26.11.01.01B (24-1); (c) a CAIR NOx allowance, as that term is defined in 40 CFR 96.102; (d) a

CAIR NO_x Ozone Season allowance, as that term is defined in 40 CFR 96.302; (e) an NO_x allowance or authorization (or similar term) as set forth in Laws that may be promulgated by the State of Maryland after the date hereof to implement the federal Clean Air Interstate Rule published in the Federal Register on May 12, 2005; and (f) an NO_x allowance or authorization (or similar term) promulgated pursuant to any future U.S. federal or state Laws that amends or supersedes any of the foregoing.

"***NO_x Budget Program***" means a statutory or regulatory program promulgated by the U.S. or a state pursuant to which the U.S. or state provides for a limit on the amount of NO_x that can be emitted by all sources covered by the program and establishes tradable allowances or authorizations as the means for ensuring compliance with the limit.

"***Off-Site Disposal Facility***" means a facility not located at the Facilities which receives from Seller or has received from Seller Hazardous Substances from the Facilities for recycling, disposal, treatment, storage or processing; provided that Off-Site Disposal Facility does not include Lot 15 or any property to which Hazardous Substances that were Released on or at the Sites or Lot 15 have migrated.

"Off-Site Disposal Liabilities" has the meaning set forth in Section 2.4(f).

"Off-Site Employees" has the meaning set forth in Section 3.18(a).

"***Outstanding Coal Support Obligations***" has the meaning set forth in Section 5.19.

"***Owned Real Property***" means collectively, each parcel of real property owned in fee by Seller that is listed on **Schedule 1.1-ORP**, together with all improvements, structures and fixtures thereon.

"***Owned Vessels***" means the vessels and barges owned by Seller and identified on **Schedule 1.1-OV**.

"***Parties***" means collectively, Buyer and Seller.

"***Permit Applications***" has the meaning given to it in Section 2.1(e).

"***Permits***" means all licenses, permits, certificates of authority, authorizations, approvals, registrations, franchises and similar consents and orders issued or granted by a Governmental Authority.

"***Permitted Contract***" means a Contract (a) entered into, terminated or amended in the ordinary course of business which will be fully performed prior to Closing (without any continuing Liability to Buyer (or its designee) on after Closing), (b) that does not increase an Assumed Liability or which increases an Assumed Liability by an amount of $250,000 or less individually or $5,000,000 or less in the aggregate with other such Contracts, (c) entered into, terminated or amended in connection with any of the planned outages identified in **Schedule 3.6** and which has a value of $2,500,000 or less in the aggregate with other such Contracts related to the planned outage (except Contracts permitted under **Section 5.4(d)**), or (d) permitted by **Section 5.4(d)**.

“***Permitted Lien***” means any of the following: (a) Liens for Taxes or other charges or assessments by any Governmental Authority to the extent that the payment thereof is not in arrears or otherwise due or is being contested in good faith (in the case of any such contest in good faith, where adequate reserves have been established to the extent required by GAAP); (b) encumbrances on real property in the nature of zoning restrictions, building and land use Laws, ordinances, orders, decrees, restrictions or any other conditions imposed by any Governmental Authority on the Owned Real Property or the Leased Real Property if the same do not have a materially adverse effect on the operation or use of such property in the business of any of the Facilities or the Acquired Assets as conducted on the Effective Date; (c) easements, title imperfections and similar matters if the same do not materially impair the value, or materially detract from the operation or use of any of the Facilities or the other Acquired Assets as conducted on the Effective Date; (d) statutory or common law liens in favor of carriers, warehousemen, mechanics and materialmen, statutory or common law liens to secure claims for labor, materials or supplies and other like liens, that secure obligations to the extent that payment thereof is not in arrears or otherwise due and that have been incurred under Good Utility Practice; (e) any Lien or title imperfection with respect to the Acquired Assets created by or resulting from any act or omission of Buyer; (f) any Lien shown on (i) that certain ALTA/ACSM Land Title Survey, dated as of June 7, 2012, prepared by Morris & Ritchie Associates, Inc. with respect to the Brandon Shores Facility and the H.A. Wagner Facility, (ii) that certain ALTA/ACSM Land Title Survey, dated as of June 15, 2012, prepared by Daft McCune Walker, Inc. with respect to the C.P. Crane Facility, or (iii) that certain ALTA/ACSM Land Title Survey, dated as of June 15, 2012, prepared by Century Engineering, Inc. with respect to the Lot 15; and (g) matters set forth on **Schedule 1.1-PL**.

“***Person***” means any natural person, corporation, general partnership, limited partnership, limited liability company, proprietorship, other business organization, trust, union, entity, association or Governmental Authority.

“***Personal Property Leases***” means all leases of personal property which relate to any of the Acquired Assets or the use, ownership, operation or maintenance of any of the Facilities.

“***PJM***” means Pennsylvania New Jersey Maryland Interconnection, LLC, a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of thirteen states and the District of Columbia.

“***PJM 5004/05***” means the combination of the Keystone-Juniata 5004 transmission line and the Conemaugh-Juniata transmission line.

“***PJM MAAC***” means the Mid-Atlantic Area Council region of the PJM region.

“***Price Differential***” has the meaning given to it in Section 5.26(c).

“***Project Capital Expenditures***” means the actual amount of capital expenditures for the projects set forth on **Schedule 1.1-BCE** and which are incurred by Seller during the Interim Period, which for purposes of clarification shall not include allocations of any indirect costs or overhead.

“***Purchase Price***” has the meaning given to it in Section 2.5.

"***Reciprocal Easement Agreement***" means a Reciprocal Easement Agreement in form and substance reasonably satisfactory to Buyer and Seller, relating to the use by Buyer and Seller of certain easements, rights of way, attachment rights or other rights of use in, on, over, and above, or with respect to, the real and personal property at the Brandon Shores Facility and the H.A. Wagner Facility, on the one hand, and Lot 1, including the Fort Smallwood office building, on the other hand; provided that the Reciprocal Easement Agreement shall not require an amendment of the Subdivision Plat Amendment as currently in effect and recorded with the applicable county.

"***Release***" means any release, spill, emission, migration, leaking, pumping, injection, deposit, disposal or discharge of any Hazardous Substances into the environment.

"***Remediation***" means an action of any kind to address an Environmental Condition or Release of Hazardous Substances, including any or all of the following activities: (a) monitoring, investigation, assessment, treatment, cleanup, containment, removal, mitigation, response or restoration work; (b) obtaining any permits, consents, approvals or authorizations of any Governmental Authority necessary to conduct any such activity; (c) preparing and implementing any plans or studies for any such activity; (d) obtaining a written notice from a Governmental Authority with jurisdiction over the Acquired Assets or any location under Environmental Laws that no material additional work is required by such Governmental Authority; (e) the use, implementation, application, installation, operation or maintenance of removal actions on the Acquired Assets or any location, remedial technologies applied to the surface or subsurface soils or sediments, excavation and treatment or disposal of soils or sediments at any location, systems for long-term treatment of surface water or ground water, engineering controls or institutional controls; and (f) any other activities reasonably determined by a party to be necessary or appropriate or required under Environmental Laws to address an Environmental Condition or a Release of Hazardous Substances. Remediation does not include payment of compensation for natural resource damages.

"***Representatives***" means, as to any Person, the officers, directors, partners, managers members, shareholders, and employees, counsel, accountants, financial advisors, sources of financing (including counsel for such sources) and consultants of such Person and its Affiliates, as applicable.

"***Responding Party***" has the meaning given to it in Section 9.4(a).

"***Restoration Cost***" has the meaning given to it in Section 5.13.

"***Review Period***" has the meaning given to it in Section 2.9(d).

"***RGGI Allowances***" has the meaning given to it in Section 5.21.

"***Schedules***" means the disclosure schedules for this Agreement.

"***Second Auction***" has the meaning given to it in Section 5.26(b).

"***Second Remainder Uncleared Capacity***" has the meaning given to it in Section 5.26(b).

“***Seller***” has the meaning given to it in the introduction to this Agreement.

“***Seller Adjustment Statement***” has the meaning given to it in Section 2.9(b).

“***Seller Employee Benefit Plan***” means (a) each “employee benefit plan,” as such term is defined in Section 3(3) of ERISA, that covers Seller Employees or Off-Site Employees, (b) each stock bonus, stock ownership, stock option, stock purchase, stock appreciation right, phantom stock, or other stock plan (whether qualified or nonqualified) that covers Seller Employees or Off-Site Employees, and (c) each bonus, incentive compensation plan or other employee plan, arrangement or program that covers Seller Employees or Off-Site Employees, in each case of clauses (a) through (c) established or maintained by Seller or its Affiliates or to which Seller or its Affiliates contributes or otherwise has any Liabilities. Seller Employee Benefit Plans do not include any Multiemployer Plans.

“***Seller Employees***” has the meaning given to it in Section 3.18(a).

“***Seller Indemnified Parties***” has the meaning given to it in Section 9.1(b).

“***Seller’s Marks***” means the names, marks and logos of Seller, Exelon, BGE and their Affiliates existing as of the Closing Date.

“***Seller’s Required Consents***” means (a) those consents, approvals, orders or authorizations of, or registrations, declarations or filings with, Governmental Authorities or Persons that are required by applicable Law, Permit or Contract in order for Seller to consummate the transactions contemplated by this Agreement and are set forth on **Schedule 1.1-SRC** attached hereto and (b) the approval of, or consent to, the transactions contemplated by this Agreement by the United States Department of Justice or, if necessary, the court overseeing the Final Judgment.

“***Sites***” means the parcels of land included in the Owned Real Property and the Leased Real Property, including the surface and subsurface elements and the soils and groundwater present at the Sites. Any references to items “at the Sites” shall include all items at, in, on, upon, over, across, under, and within the Sites.

“***SO_2***” means sulfur dioxide.

“***SO_2 Allowance***” means an allowance or authorization used to comply with an SO_2 Budget Program, including: (a) an Allowance as that term is defined in 40 CFR § 72.2; (b) a CAIR SO_2 Allowance, as that term is defined in 40 CFR 96.202; (c) an Allowance as that term is defined in Md. Environment Code Ann. § 2-1001(c)(1); (d) an SO_2 allowance or authorization (or similar term) as set forth in Laws that may be promulgated by the State of Maryland after the date hereof to implement the federal Clean Air Interstate Rule published in the Federal Register on May 12, 2005; and (e) an SO_2 allowance or authorization (or similar term) promulgated pursuant to any future U.S. federal or state Law that amends or supersedes any of the foregoing.

“***SO_2 Budget Program***” means a statutory or regulatory program, promulgated by the U.S. or a state pursuant to which the U.S. or state provides for a limit on the amount of SO_2 that can be emitted by all sources covered by the program and establishes tradable allowances or authorizations as the means for ensuring compliance with the limit.

“***Solar Facility License Agreement***” means the agreement by which Buyer shall grant to Constellation Solar Maryland, LLC certain rights specified therein, in substantially the form attached hereto as **Exhibit J**.

“***Specified Available Capacity***” has the meaning given to it in Section 5.26(a).

“***Specified Cleared Capacity***” has the meaning given to it in Section 5.26(b).

“***Support Obligations***” means, collectively, each guaranty, letter of credit, performance or surety bond or similar credit support arrangement issued by or for the account of Seller or any of its respective Affiliates in relation to the Acquired Assets or the Facilities shown on **Schedule 5.19** and, with the consent of Buyer, any other such guaranty, letter of credit, performance or surety bond or similar credit support arrangement issued by Seller or any of its respective Affiliates with respect to the Acquired Assets or the Facilities.

“***T&D***” means the transmission and distribution of electricity or natural gas.

“***T&D Assets***” means the transmission, distribution, communication, substation and other assets necessary for the current or future transmission or distribution of electricity or natural gas by Seller or its Affiliates, but does not, for the avoidance of doubt, include any Material Contract or Assigned Contract.

“***Tax***” or “***Taxes***” means (a) any federal, state, local or foreign income, franchise, gross receipts, ad valorem, sales and use, employment, social security, disability, occupation, property, severance, value added, transfer, capital stock, excise, withholding, premium, occupation or other taxes, levies or other like assessments, customs, duties, imposts, charges, surcharges or fees imposed by or on behalf of any Taxing Authority, including any interest, penalty thereon or addition thereto and (b) any Liability for amounts described in clause (a) as a result of transferee Liability, by Contract or otherwise.

“***Tax Return***” means any return, report, form, declaration, claim for refund, information report or return, statement, supplementary or supporting schedules or other information required to be filed with any Taxing Authority with respect to Taxes.

“***Taxing Authority***” means, with respect to any Tax, the governmental entity (including the Internal Revenue Service) or political subdivision thereof that imposes such Tax, and the agency (if any) charged with the collection of such Tax for such entity or subdivision.

“***Terminated Contracts***” has the meaning given to it in Section 5.6.

“***Third Auction***” has the meaning given to it in Section 5.26(b).

“***Threshold Working Capital Amount***” means an amount equal to the sum of (i) $15,000,000 if Closing occurs on or prior to October 31, 2012, (ii) $10,000,000 if Closing occurs after October 31, 2012 but on or prior to November 30, 2012, (iii) $5,000,000 if Closing occurs after November 30, 2012 but on or prior to December 31, 2012 or (iv) $0 if Closing occurs after December 31, 2012.

“***Transaction Materials***” has the meaning given to it in Section 8.2(c).

“***Transfer Taxes***” means all transfer, sales, ad valorem, use, goods and services, value added, documentary, stamp duty, gross receipts, excise, transfer and conveyance Taxes with respect to the sale or assignment of real, personal, tangible or intangible property or any interest therein and other similar Taxes, duties, fees or charges, together with any interest, penalties or additions in respect thereof.

“***Transferred Permits***” has the meaning given to it in Section 2.1(d).

“***Transferred Employee***” has the meaning given to it in Section 5.9(a).

“***Transition Services Agreement***” means a transition services agreement between Seller and Buyer and/or its designee, substantially in the form attached hereto as **Exhibit F**.

“***Welfare Benefits***” has the meaning given to it in Section 5.9(e).

“***Working Capital***” means, without duplication, the excess of (a) all current assets transferred to Buyer (or its designee) as of Closing as part of the Acquired Assets pursuant to this Agreement (excluding Fuel Inventory, other inventory, and capital spares) over (b) all current liabilities assumed by or allocable to Buyer or any of its Affiliates or designees as of Closing as an Assumed Liability pursuant to this Agreement, in the case of clauses (a) and (b): (i) excluding Excluded Assets, Excluded Liabilities, Emissions Allowances and RGGI Allowances, (ii) excluding any current assets associated with the Capital Expenditures Adjustment Amount (which shall be accounted for in the Capital Expenditures Adjustment Amount), (iii) including any current liability associated with (A) any Assigned Contract that did not transfer to Buyer or any of its Affiliates as of Closing but for which Buyer or an Affiliate is or will be allocated the burdens thereof pursuant to Section 5.22(c) or (B) Fuel Inventory, (iv) excluding mark to market accounting impacts, and (v) determined in accordance with GAAP.

“***Working Capital Adjustment Amount***” has the meaning given to it in Section 2.9(c).

Section 1.2 Rules of Construction.

(a) All article, section, subsection, schedule and exhibit references used in this Agreement are to articles, sections, subsections, schedules and exhibits to this Agreement unless otherwise specified. The exhibits and schedules attached to this Agreement constitute a part of this Agreement and are incorporated in this Agreement for all purposes.

(b) If a term is defined as one part of speech (such as a noun), it shall have a corresponding meaning when used as another part of speech (such as a verb). Unless the context of this Agreement clearly requires otherwise, words importing the masculine gender shall include the feminine and neutral genders and vice versa. The words “includes” or “including” shall mean “including without limitation,” the words “hereof,” “hereby,” “herein,” “hereunder” and similar terms in this Agreement shall refer to this Agreement as a whole and not any particular Section or article in which such words appear. Any reference to a Law shall include any amendment thereof or any successor thereto and any rules and regulations promulgated thereunder. Currency amounts referenced in this Agreement are in U.S. Dollars.

(c) Whenever this Agreement refers to a number of days, such number shall refer to calendar days unless Business Days are specified. Whenever any action must be taken hereunder on or by a day that is not a Business Day, then such action may be validly taken on or by the next day that is a Business Day.

(d) Each Party and Guarantor acknowledges that it and its attorneys have been given an equal opportunity to negotiate the terms and conditions of this Agreement and that any rule of construction to the effect that ambiguities are to be resolved against the drafting party or any similar rule operating against the drafter of an agreement shall not be applicable to the construction or interpretation of this Agreement.

(e) All accounting terms used herein and not expressly defined herein shall have the respective meanings given such terms under GAAP.

ARTICLE II
PURCHASE AND SALE AND CLOSING

Section 2.1 Purchase and Sale of Assets. Seller agrees to (or to cause its applicable Affiliate to) sell, assign and transfer to Buyer or its designee, and Buyer agrees to purchase (or cause its designee to purchase) from Seller at the Closing, subject to and upon the terms and conditions contained herein, each Facility and all of the following properties and assets used, or held for use, in the operation of any of the Facilities (collectively, the "***Acquired Assets***") free and clear of all Liens other than Permitted Liens:

(a) the Owned Real Property and the easements, rights of way, real property licenses and other real property entitlements related to the Owned Real Property or the Leased Real Property;

(b) the machinery, equipment, materials, supplies, spare parts, fixed assets, furniture, inventory, vehicles, railcars, boats, Owned Vessels and other tangible and intangible personal property owned by Seller or any of its Affiliates which is located at the Facilities (if related solely to any of the Acquired Assets) or in transit to (if related solely to any of the Acquired Assets), or otherwise used exclusively for, the Facilities or the Acquired Assets, and all applicable warranties against manufacturers or vendors, other than the Excluded Assets;

(c) all Fuel Inventory;

(d) all Permits listed on **Schedule 2.1(d)** (the "***Transferred Permits***"), to the extent transferrable; provided that Seller shall, during the Interim Period, amend such Schedule to account for applicable changes arising during the Interim Period, to the extent such changes are permitted by Section 5.4;

(e) all applications for Permits listed on **Schedule 2.1(e)** existing or, to the extent permitted by this Agreement, filed on or before the Closing Date related to any of the Facilities or the Acquired Assets ("***Permit Applications***"), to the extent transferable;

(f) all of the right, title and interest of Seller and any of its Affiliates in and to Contracts, agreements, use or occupancy agreements, licenses, subleases and leases relating to the use, ownership, operation or maintenance of any of the Facilities or the Acquired Assets, including any Leases, Personal Property Leases, in each case listed on **Schedule 2.1(f)** (the "***Assigned Contracts***"); provided that Seller shall, during the Interim Period, amend such Schedule to account for additional Contracts (including Capital Commitments) entered into during the Interim Period, to the extent such additional Contracts relate to the use, ownership, operation or maintenance of any of the Facilities or the Acquired Assets and are permitted by Section 5.4;

(g) subject to the right of Seller to the extent set forth herein to retain copies for its use, all Books and Records;

(h) the right to use the names "C.P. Crane," "Brandon Shores" and "H.A. Wagner" to the extent Seller or any of its Affiliates has the right to use the names;

(i) all of the right, title and interest of Seller and any of its Affiliates in and to the Intellectual Property listed on **Schedule 2.1(i)**; provided that Seller may, during the Interim Period, amend such Schedule with the consent of Buyer (such consent not to be unreasonably withheld) to account for applicable changes arising during the Interim Period, to the extent such changes are not prohibited by this Agreement;

(j) 100% of the equity interests in Fort Armistead Road – Lot 15 Landfill, LLC, a Delaware corporation (the "***Acquired Entity***");

(k) all vehicles, Owned Vessels and other rolling stock used in the construction, operation or maintenance of any of the Facilities, the Acquired Assets or any part thereof, but not including those relating primarily to the operation or maintenance of the Excluded Assets;

(l) the Emission Allowances identified on **Schedule 2.1(l)**; provided that Seller shall, during the Interim Period, amend such Schedule to account for any additional Emission Allowances that are granted or issued to the Facilities before the Closing Date, as contemplated by Section 5.25;

(m) all accounts and notes receivable (including those resulting from any sale of electricity, capacity or ancillary services from other current assets relating to any of the Facilities, the Assigned Contracts or the other Acquired Assets), whether allocable to a period ending on, before or after the Closing Date (except any receivables that relate exclusively to an Excluded Liability); and

(n) the rights which accrue or will accrue to Buyer or its designee under this Agreement or any of the Ancillary Agreements.

Section 2.2 Excluded Assets. Notwithstanding anything to the contrary in this Agreement, there shall be excluded from the Acquired Assets to be sold, assigned, transferred, conveyed or delivered to Buyer or its designee hereunder, and to the extent in existence on the Closing Date, there shall be retained by Seller, any and all right, title or interest to the following assets, properties and rights (collectively, the "***Excluded Assets***"):

(a) (i) the property comprising or constituting any or all of the T&D Assets located at the Sites (whether or not regarded as a "transmission," "distribution" or "generation" asset for regulatory or accounting purposes), (A) including all switchyard facilities, substation facilities and support equipment, as well as all Permits and Contracts, that relate primarily to the T&D Assets but (B) excluding any Transferred Permit, Permit Application or Assigned Contract or any "Producer's Facilities" (as such term is defined in the Operations Coordination and Interconnection Agreement, between Constellation Power Source Generation, Inc. and Baltimore Gas and Electric Company, dated June 14, 2000, effective July 6, 2011) relating solely to the Facilities, and (ii) those certain assets and facilities identified exclusively for use by Baltimore Gas and Electric Company and its Subsidiaries for telecommunications purposes;

(b) all Cash, checkbooks and canceled checks, bank deposits and property or income tax receivables or any other Tax refunds to the extent allocable to a period (or portion thereof) ending on or before the Closing Date and to the extent paid by or on behalf of Seller or its Affiliates, in each case other than any such item (i) included as a current asset in Working Capital or (ii) for which an adjustment to the Purchase Price was made pursuant to this Agreement, including Section 2.10;

(c) any properties, assets, rights, equipment, business, operation, subsidiary or division of Seller or any of its Affiliates (other than the Acquired Entity), whether tangible or intangible, real, personal or mixed, not expressly set forth in Section 2.1;

(d) any and all of Seller's rights in any contract or arrangement representing an intercompany transaction, agreement or arrangement between Seller and an Affiliate of Seller, whether or not such transaction, agreement or arrangement relates to the provisions of goods or services, payment arrangements, intercompany charges or balances or the like including, but not limited to, the Terminated Contracts, but excluding any Assigned Contract;

(e) all rights of Seller or its Affiliates (other than the Acquired Entity) in and to any causes of action against a third party (i) relating to any period ending on or before the Closing Date, or (ii) arising from any event, action or inaction occurring on or before the Closing Date, whether received as a payment or credit against future liabilities, including any rights or interests in respect of any refunds relating to certain Taxes paid by Seller for periods ending on or before the Closing Date, as such Taxes are to be prorated in accordance with Section 2.10, insurance proceeds, and, except as otherwise set forth in Section 5.14, condemnation awards, Excluded Assets or Excluded Liabilities, but excluding any such rights of Seller or its Affiliates (other than the Acquired Entity) to the extent the associated third party claims relate to an Assumed Liability or an Acquired Asset;

(f) Seller's Marks;

(g) the corporate seals, charter documents, minute books, stock books, Tax Returns (subject to Section 5.11 and Section 5.12), books of account, records having to do with the corporate organization of Seller and all other books and records of Seller and its Affiliates (other than the Acquired Entity) other than the Books and Records;

(h) the rights which accrue or will accrue to Seller under this Agreement or any of the Ancillary Agreements;

(i) insurance policies of Seller and its Affiliates and, except as otherwise provided in this Agreement (including Section 5.13), insurance proceeds therefrom;

(j) records relating to the employees of Seller and its Affiliates other than those Transferred Employees who become employed by Buyer or its Affiliates, to the extent permitted by applicable Law;

(k) software not included in the Acquired Assets;

(l) the real property consisting of Lot 1, containing 27.561 acres, more or less, as shown on the plat prepared by Morris & Ritchie Associates, Inc. entitled "Revision of Wagner-Brandon Shores Subdivision Plat, Lot 1, Tract 1 – Parcel 1, Tract 1 – Parcel 2R and Tract 3," dated June 26, 2012 and recorded or intended to be recorded among the Plat Records of Anne Arundel County, Maryland, together with (i) all improvements thereon, including the Office Building, but excluding the portions of the Shared Sanitary Sewer Line, the Warehouse Sanitary Sewer Line, and the Warehouse Storm Water Line located upon Lot 1, and (ii) subject to the terms of the Reciprocal Easement Agreement, the Fire Protection Water Supply Facilities and the Potable Water Supply Facilities, whether located on Lot 1 or on the sites of the Brandon Shores Facility or the H.A. Wagner Facility, as all such capitalized terms are defined in the Reciprocal Easement Agreement;

(m) any assets, including assets set aside in trust, with respect to employee benefit plans, programs or arrangements maintained or contributed to by Seller or its Affiliates; and

(n) the right, title and interest of Seller in, to and under all Emission Allowances of Seller or any of its Affiliates (other than the Emission Allowances set forth on **Schedule 2.1(l)**).

Section 2.3 Assumption of Liabilities. On the terms and subject to the conditions set forth herein, from and after the Closing, Buyer will assume and satisfy or perform all of the Liabilities of Seller in respect of, or otherwise arising from the ownership, operation or use of the Acquired Assets, (in each case other than the Excluded Liabilities as set forth in Section 2.4 below and other than Liabilities that are otherwise subject to indemnification by Seller pursuant to this Agreement), but in each case only to the extent expressly set forth below (the "***Assumed Liabilities***"):

(a) all Liabilities, except Off Site Disposal Liabilities, for Remediation of any Environmental Conditions in existence prior to, on or after the Closing Date;

(b) all Liabilities under (i) the Assigned Contracts, the Transferred Permits and the Permit Applications (including but not limited to the obligation to provide, subject to the provisions of Section 5.19, performance and credit assurance) in accordance with the terms thereof and (ii) the Contracts entered into by or on behalf of Seller with respect to the Acquired Assets during the Interim Period in accordance with Section 5.4 (including Capital Commitments);

(c) all Liabilities relating to Transferred Employees and occurring after the applicable Transferred Employee's Hiring Time;

(d) all Liabilities of Seller directly and exclusively related to the Acquired Assets from a violation of Law (other than any such violation which is an Excluded Liability);

(e) all Liabilities to the extent arising from or relating to the operation or use of the Facilities or Acquired Assets occurring on or after the Closing and any other Liability expressly assumed by Buyer under this Agreement; and

(f) all Liabilities of Buyer (but not of Seller or its Affiliates) arising on or after Closing (i) under any regulatory order applicable to the Acquired Assets or (ii) imposed on Buyer or the Acquired Assets in connection with any Buyer's Required Consents.

Notwithstanding anything to the contrary herein, nothing in this Section 2.3 shall limit or reduce any Buyer Indemnified Party's rights to indemnification from Seller, or Seller's obligations to indemnify the Buyer Indemnified Parties, pursuant to Section 9.1(a), including for any breach of a representation or warranty of Seller contained in Section 3.15.

Section 2.4 Excluded Liabilities. None of Buyer (or its designees) shall assume, satisfy or be responsible for the performance of any of the Liabilities of Seller or its Affiliates, except for the Assumed Liabilities. All Liabilities of Seller or its Affiliates other than the Assumed Liabilities are referred to herein as the "***Excluded Liabilities***", all of which shall remain the sole responsibility of Seller and/or its Affiliates (other than the Acquired Entity). The Excluded Liabilities include the following:

(a) any Liability of Seller and/or any of its Affiliates in respect of or otherwise arising from the ownership, lease, operation, construction, modification, operation, maintenance or use of any Excluded Assets or any other assets of Seller or any Affiliate of Seller that are not Acquired Assets;

(b) any Liability of Seller and/or any of its Affiliates in respect of (i) any Indebtedness, including any Tax exempt Indebtedness relating to any of the Acquired Assets, (ii) any service terminated pursuant to Section 5.6 or (iii) any Terminated Contract;

(c) any Liability arising out of or in connection with any Seller Employee Benefit Plan, or any Liability for the termination of any Seller Employee Benefit Plan or any Liability arising out of or in connection with any other employee benefit plan (as such term is defined in Section 3(3) of ERISA) subject to Title IV of ERISA that Seller or any of its ERISA Affiliates sponsor, maintain or contribute to or have an obligation to contribute to;

(d) any Liability relating to any employees of Seller or any of its Affiliates who do not become Transferred Employees;

(e) any Liability relating to (i) any Transferred Employee and occurring or arising before the applicable Transferred Employee's Hiring Time or (ii) any Transferred Employee's termination of employment with Seller or its Affiliates, including without limitation Liability relating to severance pay and pay for any accrued but unused vacation or other paid time off;

(f) any Liability relating to the treatment, disposal, storage, discharge, Release, recycling or the arrangement for such activities at, or the transportation to, any Off-Site Disposal Facility on or prior to the Closing Date, of Hazardous Substances that were generated at the Sites ("***Off-Site Disposal Liabilities***");

(g) any Liability for Claims relating to violations of Environmental Laws or Environmental Permits on or prior to the Closing Date;

(h) any Liability for Claims arising as a result of or in connection with any toxic tort, natural resource damages, loss of life or injury to persons due to Releases of Hazardous Substances or exposure to Hazardous Substances at, on, over, under or from the Sites on or prior to the Closing Date other than Liability for Claims in connection with or arising from Remediation by Buyer of any Environmental Condition;

(i) any Liability in respect of Taxes (i) imposed on or attributable to the Acquired Assets for any period (or portion thereof) ending on or before the Closing Date (including Seller's portion of Taxes pro-rated pursuant to Section 2.10), (ii) attributable to or measured by reference to any business, activity or operation in which the Acquired Assets were used for periods (or portion thereof) ending on or before the Closing Date, or (iii) of Seller and/or any of its Affiliates not related to the Acquired Assets or any business, activity or operation in which the Acquired Assets were used;

(j) any Liability arising out of, relating to or in connection with (i) any Claim or cause of action arising out of or relating to those matters set forth on **Schedule 3.8** or any other Claim that, as of the Closing Date, is pending against or, to Seller's Knowledge, threatened against Seller or its Affiliates with respect to the Acquired Assets, (ii) Seller's or its Affiliates' fraud, willful misconduct or criminal action arising or occurring prior to Closing, or (iii) Claims for fines or penalties with respect to violations of Law or Permit arising or occurring prior to Closing with respect to the Acquired Assets;

(k) any Liability of Seller and/or any of its Affiliates arising before, on or after Closing under, relating to or in connection with any Seller's Required Consent, the Final Judgment, the Final Order, the Hold Separate Order, the settlement agreement between the Independent Market Monitor for PJM Interconnection, L.L.C., and Exelon Corporation and Constellation Energy Group, filed on October 11, 2011, with the FERC in Docket No. EC11-83-000 and with the Maryland Public Service Commission in Case No. 9271, and/or Order No. 84698 of the Maryland Public Service Commission issued in Case No. 9271 on February 17, 2012 or any similar proceeding;

(l) any Liability of Seller or any of its Affiliates arising from or associated with any transaction between Seller and any of its Affiliates or among any of Seller's Affiliates other than any Assumed Liability with respect to an Assigned Contract where the counterparty is an Affiliate of Seller;

(m) any Liability arising from the failure to satisfy a minimum purchase or delivery volume under any Assigned Contract with respect to Fuel Inventory during the calendar year ended December 31, 2012; and

(n) any Liability of Seller and/or any of its Affiliates arising from the making or performance of this Agreement (including Seller's obligations under Section 9.1(a)) or an Ancillary Agreement or the transactions contemplated hereby or thereby.

Section 2.5 Purchase Price. Subject to the terms and conditions of this Agreement, including the last sentence of Section 2.9(f), at Closing, Buyer agrees to assume (or cause its designee to assume) the Assumed Liabilities and pay (or cause its designee to pay) to Seller an aggregate amount equal to (such amount, the "***Closing Purchase Price***") (a) the Base Purchase Price, (b) plus or minus the Estimated Proration Amount as determined under Section 2.10, (c) plus or minus the Capital Expenditures Adjustment Amount as of the Closing Date, as estimated by Seller at least five (5) days prior to the Closing (such estimate, the "***Estimated Capital Expenditures Adjustment Amount***"), and (d) plus an amount equal to the value of the Fuel Inventory as of the Closing Date, as estimated by Seller at least five (5) days prior to the Closing (such estimate, the "***Estimated Fuel Inventory Amount***"). The Closing Purchase Price shall be subject to adjustment pursuant to Sections 2.9(a), 2.9(f) and 2.10(b) and the Closing Purchase Price, as so adjusted pursuant to such Sections, shall be herein referred to as the "***Purchase Price***."

Section 2.6 Closing. The Closing shall take place at the offices of Morgan, Lewis & Bockius LLP, 1701 Market Street, Philadelphia, PA 19103 at 10:00 A.M. local time, on (a) the later of (i) the third Business Day after the conditions to Closing set forth in Articles VI and VII (other than actions to be taken or items to be delivered at Closing, but subject to satisfaction of such conditions at the Closing) have been satisfied or waived, or (ii) if agreed by Buyer and Seller in writing, on the last Business Day of the month in which the conditions to Closing set forth in Articles VI and VII (other than actions to be taken or items to be delivered at Closing, but subject to satisfaction of such conditions at the Closing) have been satisfied or waived or (b) such other date and at such other time and place as Buyer and Seller mutually agree in writing. All actions listed in Section 2.7 or 2.8 that occur on the Closing Date shall be deemed to occur simultaneously at the Closing. The Closing shall be deemed to be effective as of 11:59:59 p.m. EST on the Closing Date.

Section 2.7 Closing Deliveries by Seller to Buyer. At the Closing, Seller shall, and shall cause its Affiliates, as applicable to, deliver the following to Buyer (or its designee), duly executed and properly acknowledged, if appropriate:

(a) the Deeds;

(b) the Bills of Sale;

(c) the bills of sale substantially in the form of **Exhibit H** to convey to and vest in Buyer (or its designee) the Owned Vessels;

(d) one or more Assignment and Assumption Agreements executed by Seller and each other Affiliate of Seller (other than the Acquired Entity) that is a counterparty to an Assigned Contract or that holds a Transferred Permit or Permit Application;

(e) the Transition Services Agreement;

(f) the officer's certificates referenced in Section 6.3;

(g) a FIRPTA Affidavit;

(h) lease agreement between Seller (or one of its Affiliates), as lessor, and Buyer or its designee, as lessee, in substantially the form of **Exhibit I** with respect to the Office Building referred to in Section 2.2(l);

(i) originals (if available) or copies of all Books and Records that are not located at the Facilities;

(j) the Solar Facility License Agreement;

(k) any vehicle title, registration documents or bills of sale necessary to effect the transfer of title to the Acquired Assets comprised of motor vehicles or boats from Seller to Buyer (or its designee);

(l) any notices or other documents required by any Person (i) as necessary for Buyer to be recognized as the owner of the Acquired Assets by PJM, to replace Seller as the party to all transactions with PJM associated with the Acquired Assets, and to receive all revenue from PJM associated with the Acquired Assets or (ii) to effect the transfer from Seller to Buyer (or its designee) of the Emission Allowances identified on **Schedule 2.1(l)**;

(m) the Reciprocal Easement Agreement;

(n) evidence of termination by Seller, effective as of Closing, of the agreement attached hereto as **Exhibit K**; and

(o) such other documents as necessary to transfer the Acquired Assets to Buyer, each in form and substance reasonably satisfactory to Buyer and Seller.

Section 2.8 Closing Deliveries by Buyer to Seller. At the Closing, Buyer shall (or shall cause its designee to) deliver to Seller, duly executed and properly acknowledged, if appropriate:

(a) wire transfers of immediately available funds (to such account or accounts as Seller shall have notified Buyer of at least two (2) Business Days prior to the Closing Date) in an amount equal to the Closing Purchase Price, as adjusted by the Estimated Working Capital Amount;

(b) the Bills of Sale;

(c) the bills of sale substantially in the form of **Exhibit H** to convey to and vest in Buyer (or its designee) the Owned Vessels;

(d) the Assignment and Assumption Agreements referred to in Section 2.7 executed by Buyer or one of its Affiliates;

(e) the Transition Services Agreement;

(f) the officer's certificates referenced in Section 7.3;

(g) all applicable exemption certificates with respect to Taxes that would otherwise be imposed with respect to the transactions contemplated by this Agreement;

(h) lease agreement between Seller (or one of its Affiliates), as lessor, and Buyer or its designee, as lessee, in substantially the form of **Exhibit I** with respect to the Office Building referred to in Section 2.2(l);

(i) the Solar Facility License Agreement; and

(j) the Reciprocal Easement Agreement.

Section 2.9 Working Capital Purchase Price Adjustment.

(a) At least (5) five days prior to the Closing, Seller shall deliver to Buyer a statement (the "***Estimated Closing Statement***") reflecting Seller's good faith estimate of Working Capital as of the Closing Date (the "***Estimated Working Capital Amount***"), the Estimated Capital Expenditures Adjustment Amount and the Estimated Fuel Inventory Amount, which Estimated Closing Statement shall include a detailed calculation of each such estimated amount and be accompanied by reasonable supporting documentation. At the Closing:

(i) If the Estimated Working Capital Amount is less than the Threshold Working Capital Amount, the Closing Purchase Price shall be reduced by an amount equal to such deficiency; and

(ii) If the Estimated Working Capital Amount is greater than the Threshold Working Capital Amount, the Closing Purchase Price shall be increased by an amount equal to such excess.

(b) Within sixty (60) days after the Closing, Seller shall prepare and deliver to Buyer a statement (the "***Seller Adjustment Statement***"), together with reasonable supporting documentation, setting forth the difference between the actual Capital Expenditures Adjustment Amount as of the Closing Date and the Estimated Capital Expenditures Adjustment Amount (such difference, the "***Capital Expenditures True Up***").

(c) Within sixty (60) days after the Closing, Buyer shall prepare and deliver to Seller a statement (the "***Buyer Adjustment Statement***" and, together with the Seller Adjustment Statement, the "***Adjustment Statements***"), which sets forth (i) the difference between the actual Working Capital as of the Closing Date (the "***Closing Working Capital Amount***") and the

Estimated Working Capital Amount (such difference, the "***Working Capital Adjustment Amount***"), and (ii) the difference between the actual Fuel Inventory Amount and the Estimated Fuel Inventory Amount (such difference, the "***Fuel Inventory Adjustment Amount***" and together with the Working Capital Adjustment Amount and the Capital Expenditures True Up, each an "***Adjustment Amount***"), together with reasonable supporting documentation.

(d) The Parties agree to reasonably cooperate in connection with the preparation of the Adjustment Statements and shall provide each other with such books, records and information as may be reasonably requested from time to time in connection therewith and in connection with each Party's review thereof.

(e) Upon receipt from the preparing Party of an Adjustment Statement, the receiving Party shall have thirty (30) days to review such Adjustment Statement (the "***Review Period***"). The receiving Party may, on or prior to the last day of the Review Period, deliver a notice to the preparing Party (the "***Notice of Objection***"), which sets forth its objection to the preparing Party's calculation of any Adjustment Amount to which the receiving Party objects. Any Notice of Objection shall specify those items or amounts with which the receiving Party disagrees, together with a written explanation of the reasons for disagreement with each such item or amount, and shall set forth the receiving Party's calculation of such Adjustment Amount based on such objections, together with reasonable supporting documentation. Unless the receiving Party delivers the Notice of Objection to the preparing Party within the Review Period, the receiving Party shall be deemed to have accepted the preparing Party's calculation of the Adjustment Amounts set forth in the preparing Party's Adjustment Statement, and such Adjustment Statement shall be final, conclusive and binding. If a receiving Party timely delivers the Notice of Objection, upon expiration of such Review Period, the applicable Adjustment Statement shall become final, conclusive and binding except with respect to, and only to the extent of, those matters expressly objected to by the receiving Party in the Notice of Objection. If the receiving Party delivers the Notice of Objection to the preparing Party within the Review Period, Buyer and Seller shall, during the thirty (30) days following such delivery or any mutually agreed extension thereof, use their commercially reasonable efforts to reach agreement on the disputed items and amounts in order to determine the amount of the Closing Working Capital Amount, Fuel Inventory Amount and/or Capital Expenditures Adjustment Amount, as applicable. If such disputes are resolved, then the applicable Adjustment Statement, as adjusted for any changes agreed upon by the Parties, shall be final, binding and conclusive for all purposes hereunder. If, at the end of such period or any mutually agreed extension thereof, Buyer and Seller are unable to resolve their disagreements, they shall jointly retain and refer their disagreements to the Independent Accountant. The Independent Accountant shall base its determination solely on written submissions by Buyer and Seller and not on an independent review and shall not have the power to modify or amend any term or provision of this Agreement. The Parties shall instruct the Independent Accountant that it may not resolve any disagreement in such a way as to render the final (i) Closing Working Capital Amount greater than that which is proposed by Seller or less than that which is proposed by Buyer, (ii) Fuel Inventory Amount greater than that which is proposed by Seller or less than that which is proposed by Buyer, or (iii) Capital Expenditures Adjustment Amount greater than that which is proposed by Seller or less than that which is proposed by Buyer. Buyer and Seller shall make available to the Independent Accountant all relevant books and records and other items reasonably requested by the Independent Accountant. As promptly as practicable, but in no event later than thirty (30) days after its retention, the Independent Accountant shall deliver to Buyer and Seller a report which sets forth its resolution of the disputed items and amounts and its calculation of (as applicable) the Closing Working Capital Amount, the Capital Expenditures Adjustment Amount and/or the Fuel Inventory Amount. The decision of the Independent Accountant shall be final, conclusive and binding on the Parties. The costs and expenses of the Independent Accountant shall be shared equally by Buyer and Seller.

(f) Within ten (10) Business Days after a final determination of the Closing Working Capital Amount, Capital Expenditures Adjustment Amount, and Fuel Inventory Amount in accordance with Section 2.9(e), (i) if the finally determined Closing Working Capital Amount is greater than the Estimated Working Capital Amount, Buyer shall pay Seller the amount of such excess, (ii) if the finally determined Closing Working Capital Amount is less than the Estimated Working Capital Amount, Seller shall pay Buyer the amount of such deficiency, (iii) if the finally determined Capital Expenditures Adjustment Amount is greater than the Estimated Capital Expenditures Adjustment Amount, Buyer shall pay Seller the amount of such excess, (iv) if the finally determined Capital Expenditures Adjustment Amount is less than the Estimated Capital Expenditures Adjustment Amount, Seller shall pay Buyer the amount of such deficiency, (v) if the finally determined Fuel Inventory Amount is greater than the Estimated Fuel Inventory Amount, Buyer shall pay Seller the amount of such excess, and (vi) if the finally determined Fuel Inventory Amount is less than the Estimated Fuel Inventory Amount, Seller shall pay Buyer the amount of such deficiency. Each payment to be made under this Section 2.9(f) shall be by wire transfer of immediately available funds to an account designated by the Party entitled to receive such payment. The payments to be made pursuant to this Section 2.9(f) may, if they are due and payable within the same ten (10) Business Day period, be netted against each other. Notwithstanding anything contained in this Agreement, the maximum payment from Buyer to Seller with respect to the Closing Working Capital Amount, the Capital Expenditures Adjustment Amount and the Fuel Inventory Amount (whether paid pursuant to Section 2.8 or Section 2.9) shall not exceed $75,000,000 in the aggregate.

Section 2.10 Proration.

(a) Buyer and Seller agree that all of the Taxes listed below and such other items as are mutually agreed to by the Parties, to the extent relating to the business and operations of the Acquired Assets, shall, with respect to any period beginning on or before the Closing Date and ending after the Closing Date, be prorated as of the Closing Date, with Seller liable to the extent such items relate to any period through and including the Closing Date, and Buyer liable to the extent such items relate to periods after the Closing Date: personal property, Owned Real Property, Leased Real Property, occupancy and water Taxes, if any, on or associated with the Acquired Assets. Subject to Section 2.10(b), below, not less than five (5) Business Days prior to the Closing Date, the Parties shall agree upon the sum of the net amount of the prorated amounts to which either Seller or Buyer shall be entitled pursuant to this Section 2.10(a) and the Closing Purchase Price shall be adjusted to reflect such net amount (the "***Estimated Proration Amount***"). Any refunds, credits or similar benefits relating to the items listed in this Section 2.10(a) shall be allocated between the Parties in the same manner that the Taxes to which the refunds, credits or similar benefits relate were paid. Buyer shall promptly pay to Seller the portion of such refund, credit or similar benefit received or realized that is allocable to Seller hereunder, and Seller shall promptly pay to Buyer the portion of such refund, credit or similar benefit received or realized that is allocable to Buyer hereunder.

(b) If the amount of one or more Taxes to be prorated in accordance with Section 2.10(a) is not known or determinable on or prior to the Closing Date, the amounts to be prorated upon the Closing in accordance with Section 2.10(a) shall be based upon the actual Taxes for the preceding year (or appropriate period) for which such actual Taxes are available. The amount of Taxes prorated upon the Closing pursuant to Section 2.10(a) shall be adjusted upon the request of either Seller, on the one hand, or Buyer, on the other hand, made within sixty (60) days of the date the actual amounts become available. Seller and Buyer agree to furnish each other with such documents and other records that may be reasonably requested in order to confirm all adjustment and proration calculations made pursuant to this Section 2.10.

Section 2.11 Allocation of Purchase Price. No later than one hundred twenty (120) days after the Closing Date, Buyer shall prepare and deliver to Seller the proposed allocation of the total consideration paid by Buyer to Seller pursuant to this Agreement among the Acquired Assets for purposes of Section 1060 of the Code. The proposed allocation shall be conclusive and shall be binding upon both Buyer and Seller unless Seller objects in writing within thirty (30) days after receipt of such proposed allocation. In the event that Seller objects in writing within thirty (30) days, Buyer and Seller shall negotiate in good faith to resolve the dispute. If Buyer and Seller fail to agree on such allocation within thirty (30) days following Seller's written objection, such allocation shall be determined, within a reasonable time, by an independent, nationally recognized engineer or appraiser mutually agreed upon and selected by the Parties (the "***Independent Appraiser***") to determine the fair value of the Acquired Assets solely for purposes of such allocation under this Section 2.11. If such an appraisal is made, it shall be binding upon both Buyer and Seller. Each Party shall bear and pay one-half of the fees and other costs charged by the Independent Appraiser. Each of Buyer and Seller agrees to file Internal Revenue Service Form 8594 and all federal, state, local and foreign Tax Returns in accordance with such agreed allocation (giving effect to mutually-agreed upon adjustments as a result of adjustments to the Purchase Price pursuant to Section 2.9). Each of Buyer and Seller shall report the transactions contemplated by this Agreement and the Ancillary Agreements for federal income tax and all other Tax purposes in a manner consistent with the allocation, if agreed-upon or determined by the Independent Appraiser in each case pursuant to this Section 2.11, and, except as otherwise required by Law, neither Party nor their respective Affiliates shall take a Tax position that is inconsistent with the allocation. Each of Buyer and Seller agrees to provide the other promptly with any other information reasonably required to complete such Form 8594. Each of Buyer and Seller shall notify and provide the other with reasonable assistance in the event of an examination, audit or other proceeding regarding the agreed upon allocation of the Purchase Price.

ARTICLE III
REPRESENTATIONS AND WARRANTIES REGARDING SELLER

Seller represents and warrants to Buyer as follows:

Section 3.1 Organization. Seller, Guarantor and each Affiliate of Seller that will, at a Closing, be a party to an Ancillary Agreement, is a corporation, limited liability company, or partnership duly organized, validly existing and in good standing under the Laws of it jurisdiction of formation, and has all requisite power and authority to own, lease, and operate its material properties and assets and to carry on its business as it is now being conducted. Seller, Guarantor and each Affiliate of Seller that will, at Closing, be a party to an Ancillary Agreement, is duly qualified or licensed to do business in each jurisdiction in which the ownership or operation of the Acquired Assets make such qualification or licensing necessary, except in those jurisdictions where the failure to be so duly qualified or licensed would not have a Material Adverse Effect. The Acquired Entity is a limited liability company duly organized, validly existing and in good standing under the Laws of the State of Delaware, and has all requisite power and authority to own, lease, and operate its properties and assets and to carry on its business as it is now being conducted. The Acquired Entity is duly qualified or licensed to do business in each jurisdiction in which the ownership or operation of its assets makes such qualification or licensing necessary.

Section 3.2 Acquired Entity. Seller is the direct owner, holder of record, and beneficial owner of 100% of the equity interests of the Acquired Entity free and clear of all Liens, other than those arising pursuant to this Agreement, the organizational documents of the Acquired Entity, or applicable securities Laws. There is no agreement or option, or any right or privilege capable of becoming an agreement or option, for the purchase, delivery, sale, subscription, allotment or issue of any unissued interests, units or other securities (including convertible securities, warrants or convertible obligations of any nature) of the Acquired Entity. The Acquired Entity was formed solely for the purpose of owning the Lot 15 permits, and has never owned any other assets or operated any other business. There are no obligations of the Acquired Entity to repurchase, redeem or otherwise acquire any equity interests of, or to provide funds to or make an investment in, any Person. The Acquired Entity does not own any equity interests in any Person. Other than this Agreement and the organizational documents of the Acquired Entity, the equity interests in the Acquired Entity are not subject to any agreement restricting or otherwise relating to the voting, dividend rights or disposition of such equity interests. The Acquired Entity is the applicant for the Lot 15 Solid Waste Permit.

Section 3.3 Authorization of Transaction. Seller, each of its Affiliates party thereto and Guarantor has the requisite corporate power and authority to execute and deliver this Agreement and the Ancillary Agreements to which it is a party and, subject to receipt of all Seller’s Required Consents, to perform its obligations hereunder and thereunder. All corporate actions or proceedings to be taken by or on the part of Seller, its Affiliates party thereto and Guarantor to authorize and permit the due execution and valid delivery by each of Seller and Guarantor of this Agreement and the Ancillary Agreements to which it is a party and the instruments required to be duly executed and validly delivered by Seller or its Affiliates, as applicable, pursuant hereto and thereto, the performance by Seller, its Affiliates or Guarantor, as applicable, of its obligations hereunder and thereunder, and the consummation by Seller, its Affiliates and Guarantor, as applicable, of the transactions contemplated herein and therein, have been duly and properly taken. This Agreement and the Ancillary Agreements to which Seller is a party have been (or, in the case of the Ancillary Agreements, to which Seller’s Affiliates, as applicable, will at Closing have been) duly executed and validly delivered by Guarantor, Seller or its Affiliates, as applicable, and constitute the legal, valid and binding obligation of Guarantor, Seller or its Affiliates, as applicable, enforceable in accordance with their terms and conditions, subject to applicable bankruptcy, insolvency, reorganization, moratorium and similar laws affecting enforcement of creditors’ rights and remedies generally and to general principles of equity (regardless of whether enforcement is sought in a proceeding at law or in equity).

Section 3.4 No Conflicts; Consents and Approvals. Subject (in the case of Section 3.4(a)(i) or (c)) to Seller obtaining the Seller's Required Consents, neither the execution and the delivery or performance of this Agreement or any of the Ancillary Agreements by Guarantor, Seller or any of its Affiliates, nor the consummation of the transactions contemplated hereby or thereby, will (a) violate (i) any constitution, statute, regulation, rule, injunction, judgment, order, decree, ruling, charge, license or other Law or restriction of any Governmental Authority to which Guarantor, Seller, any of its Affiliates or any of its property (including any of the Acquired Assets) is subject or (ii) any provision of the charter or by-laws of Guarantor, Seller or such Affiliate, (b) assuming receipt of all necessary filings, waivers, approvals, consents and authorizations set forth on Schedule 3.4, conflict with, violate, result in a breach of, constitute a default under, result in the acceleration of, trigger any right of first refusal under, create in any party the right to accelerate, terminate, modify, or cancel, or require any notice under (with or without the giving of notice, the lapse of time, or both) any material Assigned Contract, Permit or Transferred Permit Application, (c) require any consent or approval of, or notice to, or filing or registration with, any Governmental Authority or (d) result in the imposition or creation of any Lien on any Acquired Asset other than Permitted Liens.

Section 3.5 Title to Acquired Assets. Except as set forth on **Schedule 3.5**, (a) each of Seller's Affiliates (as and to the extent identified in any of the Schedules hereto as the owner of, or counterparty to, Acquired Assets specified on such Schedules) or Seller, has good and valid title to the Acquired Assets free and clear of all Liens other than Permitted Liens, (b) the Acquired Assets constitute all assets used or held for use by Seller and its Affiliates in, and necessary and sufficient for, the operation of each of the Facilities as presently operated, consistent with Good Utility Practice and (c) the Acquired Entity has all material assets necessary and sufficient for the operation of its business as currently conducted consistent with Good Utility Practice.

Section 3.6 Assets Used in the Operation of the Facilities. Each Facility and Acquired Asset is operational and in good working order in all material respects, ordinary wear and tear excepted, consistent with Good Utility Practice, subject to those planned outages identified in **Schedule 3.6**. Neither Seller nor its Affiliates has deferred maintenance of any Acquired Asset in contemplation of the purchase and sale of the Acquired Assets hereunder.

Section 3.7 Non-Infringement. Except as set forth on **Schedule 3.7**, (a) to Seller's Knowledge, Seller's and each of its Affiliates', as applicable, use and operation of the Acquired Assets does not infringe and has not, in the preceding five years, infringed on the rights of any Person, and (b) none of Seller or its Affiliates has received written notice from any Person that Seller's or any of its Affiliates' use and operation of any of the Acquired Assets infringes on the rights of any Person.

Section 3.8 Legal Proceedings. Except as set forth on **Schedule 3.8**, no Claim is pending against, and, to Seller's Knowledge, none has been threatened against Seller or its Affiliates, that (a) adversely affects or relates to any of the Acquired Assets or (b) seeks a writ, judgment, order, injunction or decree restraining, enjoining or otherwise prohibiting or making illegal any of the transactions contemplated by this Agreement.

Section 3.9 Compliance with Laws. Except as set forth on **Schedule 3.9**, Seller and its applicable Affiliates (including the Acquired Entity) are and for the preceding four (4) years have been in material compliance with all Laws applicable to the Acquired Assets (including (a) the Hold Separate Order, (b) the Final Judgment, and (c) the rules and regulations of, and the provisions of the applicable rate schedule of Seller or its Affiliates on file with the Federal Energy Regulatory Commission). The representations and warranties contained in this Section shall be deemed not to apply to Tax matters (which are addressed in Section 3.11), Permits (which are addressed in Section 3.14), environmental matters (which are addressed in Section 3.15), employment matters (which are addressed in Section 3.18), or employee benefit matters (which are addressed in Section 3.19).

Section 3.10 Condemnation. Except as set forth on **Schedule 3.10**, Seller and each of its Affiliates have received no written notice from any Governmental Authority of any pending or threatened proceeding to condemn or take by power of eminent domain or otherwise, by any Governmental Authority, all or any material part of the Acquired Assets.

Section 3.11 Taxes. With respect to material Taxes relating to the Acquired Assets or any business, operation or activity in which the Acquired Assets were used, (i) Seller has filed all Tax Returns that it was required to file with respect to such Taxes, and such Tax Returns are true, correct and complete in all material respects, (ii) any such Taxes that have become due have been paid in full, except where Seller is contesting the same in good faith by appropriate proceedings and has made adequate provision for the payment of such contested taxes and (iii) there is no pending claim for any such Taxes and no assessment, deficiency, or adjustment has been asserted or proposed in writing. There are no liens for Taxes on the Acquired Assets other than Permitted Liens. Other than the real property described in Section 2.2(l), all of the Acquired Assets have been properly listed and described on the property tax rolls of the appropriate Taxing Authority during the past three (3) years. The Acquired Entity is, and has been since its formation, an entity that is disregarded as separate from its owner for federal income tax purposes.

Section 3.12 Contracts.

(a) Excluding the Terminated Contracts, **Schedule 3.12** sets forth a list of the following Contracts which relate to any of the Acquired Assets or the Seller Employees (the Contracts listed on **Schedule 3.12** that meet the descriptions in this Section 3.12 being collectively, the "***Material Contracts***"):

(i) Contracts for the future purchase, exchange, sale, storage, or refining of Fuel Inventory or for the supply of water or utility services;

(ii) Contracts for the future purchase, exchange, transmission or sale of electric power in any form, including energy, capacity or any ancillary services;

(iii) Contracts for the future transportation of coal or other Fuel Inventory;

(iv) interconnection Contracts;

(v) operation and maintenance Contracts which provide for payments in excess of $250,000 in any one year period or $1,000,000 in the aggregate with other such Contracts;

(vi) Contracts which impose a security interest on any of the Acquired Assets;

(vii) any collective bargaining Contracts, Contracts with labor unions or representatives of employees, or other employment or employment-related (including severance, retention, change of control and bonus) Contracts;

(viii) outstanding futures, swap, hedge, collar, put, call, floor, cap, option or other Contracts that are intended to benefit from or reduce or eliminate the risk of fluctuations in interest rates or the price of commodities, including electric power, in any form, including energy, capacity or any ancillary services, natural gas or securities; and

(ix) Contracts with any individuals providing services at the Facilities or with respect to the Acquired Assets in the capacity of an independent contractor which provide for payments in excess of $250,000 in any one year period or $1,000,000 in the aggregate with other such Contracts;

(x) Contracts for the use of Lot 15 for the disposal of coal combustion by-products generated at any of the Facilities;

(xi) partnership, joint venture, or limited liability company agreements;

(xii) Contracts between Seller or any of its Affiliates, on the one hand, and any Affiliate of Seller or Seller, on the other hand;

(xiii) Contracts (including Personal Property Leases and the Leases) (A) which contain outstanding manufacturer's, vendor's or other warranties which provide for payment in excess of $250,000, (B) to which the Acquired Entity is a party or (C) which relate to facilities, property or equipment used both in connection with the operation of the Acquired Assets and the operation of assets other than the Acquired Assets;

(xiv) Contracts (A) under which any Person has created, incurred, assumed or guaranteed any outstanding Indebtedness, or (B) for any outstanding agreement of guaranty or surety, whether direct or indirect;

(xv) Contracts that limit the freedom of Seller or its Affiliates to compete in any line of business or in any geographical area with respect to the operation of the Facilities or the Acquired Assets;

(xvi) Contracts relating to the settlement of any Claim relating to the Acquired Assets or Assumed Liabilities; and

(xvii) other than Contracts of the nature addressed by Section 3.12(a)(i)-(iii), any Contract (A) for the future purchase or sale of any asset or service (including engineering, procurement and construction Contracts) or (B) that grants a right or option to purchase or sell in the future any asset or service, other than in each case any Contract with a remaining value of less than $250,000 in any one year period or $1,000,000 in the aggregate with other such Contracts.

(b) Seller has provided to Buyer a true and complete copy of each Material Contract. Each of the Material Contracts is in full force and effect in all material respects and constitutes a legal, valid and binding obligation of Seller and its Affiliates, as applicable, and, to Seller's Knowledge, of the other parties thereto. None of Seller or its Affiliates is in material breach of any Material Contract, and to Seller's Knowledge, no other party to any of the Material Contracts is in material breach or material default thereunder. There are no unsatisfied minimum purchase or delivery volumes with respect to Fuel Inventory for the calendar year ending December 31, 2012.

Section 3.13 Insurance. **Schedule 3.13** sets forth all material policies, binders and bonds of fire, liability and other forms of insurance owned or held by Seller or its Affiliates insuring the Acquired Assets. Each such policy is in full force and effect, all premiums with respect thereto covering all periods up to and including the date as of which this representation is being made have been paid or will be paid prior to any applicable payment due date (other than retroactive premiums that may be payable with respect to comprehensive general liability and worker's compensation insurance policies), and no written notice of cancellation or termination has been received with respect to any such policy that was not replaced on substantially similar terms prior to the date of such cancellation. **Schedule 3.13** sets forth a list of all pending claims that have been made under any such policy with respect to any of the Acquired Assets. Except as described in **Schedule 3.13**, neither Seller nor its Affiliates has been refused any material insurance with respect to the Acquired Assets nor has coverage been limited in any material respect by any insurance carrier to which any of Seller or its Affiliates has applied for any such insurance or with which it has carried insurance, in each case, during the last twelve months.

Section 3.14 Permits.

(a) **Schedule 3.14** sets forth all Permits that are material to the ownership or operation of the Acquired Assets in the manner in which they are currently owned and operated consistent with Good Utility Practice, each of which is held by Seller or its Affiliates. Seller has provided Buyer with a true and correct copy of each such Permit. None of Seller or its Affiliates has received any written notification from any Governmental Authority alleging that it is in material violation of any such Permits.

(b) All such Permits set forth on **Schedule 3.14** are in full force and effect without any material defects, and Seller and its Affiliates, as applicable, are, and for the preceding four (4) years have been, in material compliance with all such Permits. The representations and warranties contained in this Section 3.14 shall be deemed not to apply to Environmental Permits (which are addressed in Section 3.15).

Section 3.15 Environmental Matters. Except as set forth on **Schedule 3.15** or in the "Findings and Conclusions" or comparable summary sections of any environmental site assessment reports prepared by or for Seller and made available to Buyer:

(a) **Schedule 3.15(a)** sets forth all Permits required for Seller or its Affiliates to operate the Acquired Assets under applicable Environmental Laws ("***Environmental Permits***"), each of which is held by Seller or its Affiliates. Seller and its Affiliates are, and for the preceding four (4) years have been, in material compliance with applicable Environmental Laws and Environmental Permits with respect to the Acquired Assets. There are no material defects in the Environmental Permits and each Environmental Permit is in full force and effect and there are, to the Knowledge of Seller, no appeals, challenges or proceedings pending with respect to any of the Environmental Permits. Seller has provided Buyer with a true and correct copy of each such Environmental Permit.

(b) During the preceding four (4) years, none of Seller or its Affiliates has received any written request for information, or been notified in writing that it is a potentially responsible party, under CERCLA or any similar Law with respect to any of the Acquired Assets, or any written notice relating to any Person's allegation or investigation of any material violations by Seller or any of its Affiliates of any Environmental Laws or any Environmental Permits, or any written notice of any material Environmental Claim, with respect to any of the Acquired Assets.

(c) With respect to the Acquired Assets, none of Seller or its Affiliates has entered into or agreed to any consent decree or order, and is not subject to any material judgment, decree, or judicial order relating to compliance with any Environmental Laws or to Remediation of Hazardous Substances.

(d) To the Knowledge of Seller, no Environmental Condition exists, and no Release of Hazardous Substances has occurred at, on, in, over, from, or under the Sites, that has given rise or could reasonably be expected to give rise to a material Environmental Claim or a material Remediation obligation.

(e) To the Knowledge of Seller, there are no transformers or other electrical equipment containing polychlorinated biphenyls at concentrations subject to regulation under Environmental Laws located at any of the Sites or included in the Acquired Assets.

(f) Seller has provided or made available to Buyer copies of all reports, documents, and correspondence in Seller's or its Affiliate's possession or control reflecting (i) any pending material Environmental Claim; (ii) any existing Environmental Condition that could reasonably be expected to give rise to a material Environmental Claim or a material Remediation obligation; (iii) any material noncompliance with or violation of any Environmental Laws or Environmental Permits that may have occurred during the preceding four (4) years; or (iv) any appeal, challenge, or proceeding pending with respect to any of the Environmental Permits, in each case with respect to items (i), (ii), (iii) and (iv), relating to the Acquired Assets.

(g) No wetlands mitigation is required in connection with constructing, developing, or operating Lot 15 as it is currently proposed in the pending Lot 15 Solid Waste Permit application.

Section 3.16 Real Property.

(a) Except as set forth on **Schedule 3.16(a)**, (i) Seller has good, valid and marketable title in fee simple to each parcel of Owned Real Property, together with good and marketable title to all rights, privileges, interests, easements and appurtenances now or hereafter belonging or in any way pertaining to such real property, and to all of the buildings, structures and other improvements thereon, subject to no Liens except for Permitted Liens, and (ii) no Person, other than Seller, has any occupancy or use rights with respect to the Owned Real Property.

(b) **Schedule 3.16(b)** describes all of the real property leases, licenses and occupancy agreements used in the operation of any of the Facilities or the Acquired Assets and to which Seller or any of its Affiliates is a party as lessee, sublessee, tenant, subtenant or in a similar capacity (each, a "***Lease***" and collectively, the "***Leases***") and sets forth the address or legal description of each parcel of real property that is the subject of any Lease (the "***Leased Real Property***"). Except as set forth in **Schedule 3.16(b)**, Seller has a valid leasehold interest or license in the Leased Real Property, subject to no Lien except for Permitted Liens, and no Person other than Seller, has any occupancy or use rights with respect to the Leased Real Property, and each Lease is in full force and effect in all material respects and constitutes a legal, valid and binding obligation of Seller and, to Seller's Knowledge, of the other parties thereto. Seller is not in material breach of any Lease, and to Seller's Knowledge, no other party to any of the Leases is in material breach or material default thereunder.

(c) Each of Seller and its Affiliates (i) is in material compliance with all material covenants, easements and restrictions affecting the Sites, (ii) is not currently in material default under any material agreement, order, judgment or decree relating to the Sites, (iii) has not received any written notice of any material claims, causes of action, lawsuits or legal proceedings pending or threatened regarding the ownership, use or possession of the Sites, and (iv) has not received any written notice of any material violation of any zoning, subdivision, platting, building, fire, insurance, safety, health, or other applicable Laws (whether related to the Sites or the occupancy thereof).

(d) To Seller's Knowledge, none of Seller or its Affiliates has any obligation to any Person (other than pursuant to a Material Contract or a Permitted Lien), which commitment relates to the Owned Real Property and could become an Assumed Liability, in each case to pay or contribute property or money or to construct, install or maintain any improvements on or off the Owned Real Property.

(e) Except as set forth on **Schedule 3.16(b)**, Seller has no Knowledge of any fact or condition existing which could reasonably be expected to result in the termination or reduction of the current access from the Owned Real Property to the existing highways and road that provides access to the Owned Real Property, or of any reduction in or to sewer or other utility services presently serving the Owned Real Property.

(f) Seller has delivered or made available to Buyer true, complete and correct copies of Seller's and its Affiliate's existing title policies insuring the Owned Real Property.

Section 3.17 Intellectual Property. **Schedule 3.17** discloses all material Intellectual Property owned, licensed or leased by Seller or its Affiliates and used for the operation of any of the Facilities or the Acquired Assets as presently operated. Seller has all right, title and interest in or valid and binding rights to use such Intellectual Property without material limitation or Liens except for Permitted Liens. To Seller's Knowledge, none of such Intellectual Property included in the Acquired Assets is being infringed by any Person. To Seller's Knowledge, none of Seller or its Affiliates is infringing or has received written notice that it is materially infringing (or allegedly infringing) any Intellectual Property of any other Person in connection with the operation of the Facilities or the Acquired Assets.

Section 3.18 Employees and Labor Matters.

(a) **Schedule 3.18(a)** sets forth (i) a list of all employees of Seller or its Affiliates employed at the Facilities (including individuals on vacation, short-term disability, long-term disability or other leave) as of the Effective Date ("***Seller Employees***"), which such list shall be amended as of the Closing Date to include such employees so employed immediately prior to the Closing Date, (ii) a list of those employees of Seller or its Affiliates whose job responsibilities are primarily related to the Facilities but are not employed at the Facilities as set forth on **Schedule 5.9(b)** ("***Off-Site Employees***"), and (iii) a description of each Seller Employee's current base salary or wage rate, target bonus and other compensation (and potential compensation) for the 2012 fiscal year (if any), position, date of hire (and, if different, years of recognized service), status as exempt or non-exempt under the FLSA, details of any applicable visa, leave status (including nature and duration of any leave and benefits available to such individual).

(b) No Seller Employees or Off-Site Employees are covered by any collective bargaining or union contracts; and no Seller Employee or Off-Site Employee is represented by any labor union. To Seller's Knowledge, no union representation petition or organizing campaign is pending or threatened with respect to any Seller Employee or Off-Site Employee. With respect to the business and operations of the Facilities and the Acquired Assets, except to the extent set forth on **Schedule 3.18(b)**, (i) each of Seller and its Affiliates is in material compliance with all applicable Laws respecting labor and labor practices, employment and employment practices, terms and conditions of employment and wages and hours, (ii) none of Seller or its Affiliates has received notice of any unfair labor practice complaint against Seller or its Affiliates pending before the National Labor Relations Board with respect to any Seller Employee or Off-Site Employee, and (iii) no arbitration proceeding arising out of or under any collective bargaining agreements is pending against Seller or its Affiliates with respect to any Seller Employee or Off-Site Employee.

Section 3.19 Employee Benefits.

(a) **Schedule 3.19** contains a list of all Seller Employee Benefit Plans in which any Seller Employee or Off-Site Employee participates or is offered participation. With respect to each such Seller Employee Benefit Plan, Seller has made available to Buyer a copy (or, to the extent no such copy exists, an accurate description) thereof and, to the extent applicable any related trust agreement or other funding instrument and most recent Form 5500, and any currently applicable summary plan description with respect thereto.

(b) Each Seller Employee Benefit Plan has been established and administered in accordance with its terms in all material respects, and in compliance with the applicable provisions of ERISA, the Code and other applicable Laws, rules and regulations in all material respects, and no event has occurred and no condition exists with respect to any such Seller Employee Benefit Plan that would be reasonably likely to subject Buyer or its Affiliates to any material Liability.

Section 3.20 Brokers. Except as set forth in **Schedule 3.20**, none of Seller or its Affiliates has any Liability or obligation to pay any fees or commissions to any broker, finder or agent with respect to the transactions contemplated by this Agreement for which Buyer or its Affiliates could become liable or obligated.

Section 3.21 No Indebtedness. Other than the Tax exempt Indebtedness to be paid in full at or prior to Closing by or on behalf of Seller as contemplated by Section 6.7, there is no Indebtedness of Seller or any of its Affiliates relating to any of the Acquired Assets that will be or become an Assumed Liability on or after Closing.

Section 3.22 Vessel Matters.

(a) Each Owned Vessel that is documented under the laws of the United States is documented with a valid endorsement pursuant to 46 USC § 12112 to engage in coastwise trade and each Owned Vessel that is not documented under the laws of the United States is exempt from documentation pursuant to 46 USC § 12102.

(b) Except as set forth in **Schedule 3.22**, there are no outstanding CG-835 certificates or Captain of the Port orders with respect to the Owned Vessels or their respective operations.

(c) Except as set forth in **Schedule 3.22**, no Owned Vessel is a scheduled vessel of a Capital Construction Fund or Construction Reserve Fund, or is subject to any trading restriction of any nature whatsoever, including without limitation, contractual trading restrictions, other than customary restrictions contained in the insurance policies covering the Owned Vessels or with respect to the Owned Vessels' classification by the American Bureau of Shipping.

(d) Seller has exercised due diligence to keep and maintain each of the Owned Vessels seaworthy in all material respects. Except as set forth in **Schedule 3.22**, each of the Owned Vessels is equipped with hatch covers, rigging, anchors, chains, cable, tack, apparel, accessories, equipment, inventory, spare parts, and all other appurtenances necessary for the operation of such Owned Vessel in ordinary course of business consistent with past practice and Good Utility Practice.

Section 3.23 Financial Statements; Undisclosed Liabilities; Absence of Changes.

(a) Prior to the Effective Date of this Agreement, Buyer has been provided with copies of the audited combined financial statements of Maryland Clean Coal as of December 31, 2011 (the balance sheet included in such financial statements, the "***Balance Sheet***"). Such audited combined financial statements reflect the historical results of operations, assets and liabilities that comprise Maryland Clean Coal since the business does not constitute a separate legal entity. Such audited combined financial statements present in all material respects, the financial position, results of operations and cash flows of Maryland Clean Coal for the period ended December 31, 2011 in conformity with GAAP.

(b) The Acquired Entity does not have any liabilities, and there are no liabilities with respect to any of the Acquired Assets, in each case that would be required to be included on a balance sheet in accordance with GAAP except (i) as reflected or reserved in the Balance Sheet (excluding any Excluded Liabilities reflected therein), (ii) liabilities incurred in the ordinary course of business consistent with past practice since the date of the Balance Sheet that would not reasonably be expected, individually or in the aggregate, to be material in amount or nature (excluding any Excluded Liabilities), (iii) liabilities included in Working Capital, (iv) liabilities arising under Terminated Contracts, Excluded Liabilities or any services to be terminated in accordance with Section 5.6, (v) liabilities to be fully satisfied prior to Closing, or (vi) as set forth on **Schedule 3.23(b)**.

(c) Since December 31, 2011, there has not been a Material Adverse Effect nor is there any fact, event, or circumstance that is reasonably likely to result in a Material Adverse Effect.

Section 3.24 Disclaimers Regarding Acquired Assets. EXCEPT FOR ANY REPRESENTATIONS AND WARRANTIES SET FORTH IN THIS ARTICLE III, THE ACQUIRED ASSETS ARE SOLD “AS IS, WHERE IS,” AND SELLER EXPRESSLY DISCLAIMS ANY REPRESENTATIONS OR WARRANTIES OF ANY KIND OR NATURE, EXPRESS OR IMPLIED, AS TO LIABILITIES, OPERATIONS OF THE FACILITIES, TITLE, CONDITION, VALUE OR QUALITY OF THE ACQUIRED ASSETS OR THE PROSPECTS (FINANCIAL AND OTHERWISE), RISKS AND OTHER INCIDENTS OF THE ACQUIRED ASSETS INCLUDING WITH RESPECT TO THE ACTUAL OR RATED GENERATING CAPABILITY OF THE FACILITIES OR THE ABILITY OF BUYER TO SELL FROM THE FACILITIES ELECTRIC ENERGY, CAPACITY OR OTHER PRODUCTS, AND SELLER SPECIFICALLY DISCLAIMS ANY REPRESENTATION OR WARRANTY OF MERCHANTABILITY, USAGE, OR SUITABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE WITH RESPECT TO THE ACQUIRED ASSETS, OR ANY PART THEREOF, OR AS TO THE WORKMANSHIP THEREOF, OR THE ABSENCE OF ANY DEFECTS THEREIN, WHETHER LATENT OR PATENT, OR COMPLIANCE WITH ENVIRONMENTAL REQUIREMENTS, OR AS TO THE CONDITION OF THE ACQUIRED ASSETS, OR ANY PART THEREOF, INCLUDING WHETHER SELLER POSSESSES SUFFICIENT REAL PROPERTY OR PERSONAL PROPERTY TO OPERATE THE ACQUIRED ASSETS, IN EACH CASE EXCEPT AS SET FORTH HEREIN. EXCEPT AS OTHERWISE EXPRESSLY PROVIDED HEREIN, SELLER FURTHER SPECIFICALLY DISCLAIMS ANY REPRESENTATION OR WARRANTY REGARDING THE ABSENCE OF HAZARDOUS SUBSTANCES OR LIABILITY OR POTENTIAL LIABILITY ARISING UNDER ENVIRONMENTAL LAWS. WITHOUT LIMITING THE GENERALITY OF THE FOREGOING, EXCEPT AS EXPRESSLY PROVIDED HEREIN, SELLER EXPRESSLY DISCLAIMS ANY REPRESENTATION OR WARRANTY OF ANY KIND REGARDING THE CONDITION OF THE ACQUIRED ASSETS OR THE SUITABILITY OF THE FACILITIES FOR OPERATION AS A POWER PLANT OR AS A SITE FOR THE DEVELOPMENT OF ADDITIONAL OR REPLACEMENT GENERATION CAPACITY. IN FURTHERANCE OF THE FOREGOING, EXCEPT FOR THE REPRESENTATIONS AND

WARRANTIES CONTAINED IN THIS AGREEMENT, BUYER ACKNOWLEDGES AND AGREES THAT NONE OF SELLER OR ANY OF ITS AFFILIATES WILL HAVE OR BE SUBJECT TO ANY LIABILITY TO BUYER OR ANY AFFILIATE OF BUYER FOR, AND SELLER HEREBY DISCLAIMS ALL LIABILITY AND RESPONSIBILITY FOR, ANY REPRESENTATION, WARRANTY, PROJECTION, FORECAST, STATEMENT, OR INFORMATION MADE, COMMUNICATED, OR FURNISHED (ORALLY OR IN WRITING) TO BUYER OR ANY OF BUYER REPRESENTATIVES, INCLUDING ANY CONFIDENTIAL MEMORANDA, QUESTION AND ANSWER LOG, MANAGEMENT PRESENTATION OR FINANCIAL MODEL DISTRIBUTED ON BEHALF OF SELLER RELATING TO THE ACQUIRED ASSETS, OR THE ASSUMED LIABILITIES OR OTHER PUBLICATIONS OR DATA ROOM INFORMATION PROVIDED TO BUYER OR BUYER REPRESENTATIVES, OR ANY OTHER DOCUMENT OR INFORMATION IN ANY FORM PROVIDED TO BUYER OR BUYER REPRESENTATIVES IN CONNECTION WITH THE SALE OF THE ACQUIRED ASSETS, THE ASSUMPTION OF THE ASSUMED LIABILITIES, AND THE TRANSACTIONS CONTEMPLATED HEREBY (INCLUDING ANY OPINION, INFORMATION, PROJECTION, OR ADVICE THAT MAY HAVE BEEN OR MAY BE PROVIDED TO BUYER OR BUYER REPRESENTATIVES BY ANY OF SELLER'S REPRESENTATIVES). NOTHING IN THIS DISCLAIMER OR THIS AGREEMENT SHALL BE DEEMED TO AFFECT THE RIGHTS AND OBLIGATIONS OF THE PARTIES IN RESPECT OF ANOTHER PARTY'S FRAUD OR UNDER ANY ANCILLARY AGREEMENT FOR A BREACH OF ANY REPRESENTATION, WARRANTY OR COVENANT CONTAINED IN SUCH ANCILLARY AGREEMENT.

ARTICLE IV
REPRESENTATIONS AND WARRANTIES OF BUYER

Buyer represents and warrants to Seller as follows:

Section 4.1 Organization. Buyer is a limited liability company duly organized, validly existing and in good standing under the Laws of the State of Delaware, and has all requisite power and authority to own, lease, and operate its material properties and assets and to carry on its business as it is now being conducted. Each Affiliate of Buyer that will, at Closing, be a party to an Ancillary Agreement will, at Closing, be an entity duly organized and validly existing under the Laws of the state if its incorporation or organization, as applicable. Buyer is duly qualified or licensed to do business in each jurisdiction where the actions to be performed by it under this Agreement makes such qualification or licensing necessary, except in those jurisdictions where the failure to be so qualified or licensed would not have a material adverse effect on its ability to perform such actions.

Section 4.2 Authorization of Transaction. Buyer has, and each of its Affiliates that will at Closing be a party to an Ancillary Agreement will have at Closing, the requisite limited liability or other company power and authority to execute and deliver this Agreement and the Ancillary Agreements to which it is a party and, subject to receipt of all Buyer's Required Consents, to perform its obligations hereunder and thereunder. All limited liability or other company actions or proceedings to be taken by or on the part of Buyer and any of its Affiliates that will at Closing be a party to an Ancillary Agreement to authorize and permit the due execution and valid delivery by Buyer of this Agreement, and by Buyer and the applicable

Affiliate of Buyer, as applicable, of the Ancillary Agreements to which it is a party and the instruments required to be duly executed and validly delivered by Buyer and such Affiliate, as applicable, pursuant hereto and thereto, the performance by Buyer and such Affiliate of its obligations hereunder and thereunder, and the consummation by Buyer and such Affiliate, as applicable, of the transactions contemplated herein and therein, have been (or, in the case of any such Affiliate of Buyer, will at Closing have been) duly and properly taken. This Agreement has been, and the Ancillary Agreements will at Closing have been, duly executed and validly delivered by Buyer and the Affiliates of Buyer party thereto, as applicable, and constitute the valid and legally binding obligations of Buyer and such Affiliates, as applicable, enforceable in accordance with their terms and conditions, subject to applicable bankruptcy, insolvency, reorganization, moratorium and similar laws affecting enforcement of creditors' rights and remedies generally and to general principles of equity (regardless of whether enforcement is sought in a proceeding at law or in equity).

Section 4.3 No Conflicts; Consents and Approvals. Subject to Buyer obtaining the Buyer's Required Consents, neither the execution and the delivery or the performance of this Agreement or any of the Ancillary Agreements by Buyer, nor the consummation of the transactions contemplated hereby or thereby, will (a) violate any constitution, statute, regulation, rule, injunction, judgment, order, decree, ruling, charge, license or other Law or restriction of any Governmental Authority to which Buyer is subject or any provision of the organizational documents of Buyer, or (b) assuming receipt of all necessary filings, waivers, approvals, consents and authorizations, conflict with, violate, result in a breach of, constitute a default under, result in the acceleration of, trigger any right of first refusal under, create in any party the right to accelerate, terminate, modify, or cancel, or require any notice under (with or without the giving of notice, the lapse of time, or both) any agreement, contract, lease, license, instrument, or other arrangement to which Buyer is a party or by which it is bound or to which any of its assets is subject, except for matters that would not reasonably be expected to materially and adversely affect the ability of Buyer to perform its obligations hereunder.

Section 4.4 Legal Proceedings. Buyer has not been served with notice of any Claim, and to Buyer's knowledge, none is threatened in writing, against Buyer which seeks a writ, judgment, order or decree restraining, enjoining or otherwise prohibiting or making illegal any of the transactions contemplated under this Agreement or any Ancillary Agreements to which Seller is a party.

Section 4.5 Compliance with Laws and Orders. Buyer is not in violation of or in default under any Law applicable to Buyer or its assets the effect of which, in the aggregate, would reasonably be expected to hinder, prevent or delay Buyer from performing its obligations under this Agreement or any Ancillary Agreements to which Buyer is (or, in the case of the Ancillary Agreements, will be at Closing) a party.

Section 4.6 Availability of Funds. Buyer (a) will have at the Closing sufficient internal funds (without giving effect to any unfunded financing regardless of whether any such financing is committed) available to pay the Purchase Price and any expenses incurred by Buyer in connection with the transactions contemplated by this Agreement, and (b) will have at the Closing the resources and capabilities (financial or otherwise) to perform its obligations hereunder (including the Assumed Liabilities) and under any Assigned Contracts to which it becomes a party, in each case that is required to perform on such date.

Section 4.7 No Conflicting Contracts. Neither Buyer nor any of its Affiliates owns, operates, leases or controls, or is a party to any Contract to build, develop, acquire or operate, any power generation facility that would reasonably be expected to prevent or cause a delay in any Governmental Authority's granting of a Buyer's Required Consent or a Seller's Required Consent, and neither Buyer nor any of its Affiliates has any plans to enter into any such Contract prior to the Closing Date.

Section 4.8 Affiliate Representations and Warranties. If Buyer assigns its rights and interests to an Affiliate or Affiliates pursuant to Section 10.8 hereof, Buyer shall be deemed to have made the representations and warranties in this Article IV on behalf of itself and any such Affiliate as if such Affiliate were a signatory to this Agreement.

Section 4.9 Brokers. None of Buyer or its Affiliates has any Liability or obligation to pay any fees or commissions to any broker, finder or agent with respect to the transactions contemplated by this Agreement for which Seller could become liable or obligated.

Section 4.10 Opportunity for Independent Investigation; No Other Representations. Prior to its execution of this Agreement, Buyer has conducted to its satisfaction an independent investigation and verification of the current condition and affairs of the Facilities and the Acquired Assets. In making its decision to execute this Agreement and to purchase the Acquired Assets and assume the Assumed Liabilities, Buyer has relied and will rely solely upon the results of such independent investigation and verification and the terms and conditions of this Agreement (including the representations of Seller set forth in Article III and in the instruments to be delivered hereunder). Buyer acknowledges that: (a) it has had the opportunity to visit with Seller and meet with its Representatives to discuss the Facilities and the Acquired Assets and their condition, cash flows and prospects, (b) all materials and information requested by Buyer have been provided to Buyer to Buyer's reasonable satisfaction; and (c) except as set forth in Article III or in the instruments to be delivered hereunder, none of Seller, its Representatives or any Affiliate thereof has made or makes any representation or warranty, express or implied, as to the Facilities, the Acquired Assets or the Assumed Liabilities.

Section 4.11 PJM Matters. Buyer and its Affiliates do not, in the aggregate, own or control 3% or more of the installed capacity in the overall PJM market, in the PJM MAAC submarket, or in the PJM 5004/05 submarket. Neither Buyer nor any of its Affiliates have purchased or entered into any agreement to purchase any electricity or energy offered by Seller or its Affiliates pursuant to or as a result of the 500 MW Commitment.

ARTICLE V
COVENANTS

The Parties hereby covenant and agree as follows:

Section 5.1 General. Prior to the Closing and subject to the terms and conditions of this Agreement, each of the Parties will use its commercially reasonable efforts to take all actions required of it by this Agreement that are necessary, proper or advisable in order to consummate and make effective the transactions contemplated by this Agreement and the Ancillary Agreements (including satisfaction, but not waiver, of the closing conditions set forth in Articles VI and VII that such Person is required to satisfy).

Section 5.2 Regulatory and Other Approvals. During the Interim Period:

(a) Each Party will and will cause its respective applicable Affiliates to, in order to consummate the transactions contemplated hereby, (i) take all commercially reasonable steps necessary, and proceed diligently and in good faith and use all commercially reasonable efforts, to obtain as promptly as practicable the Seller's Required Consents and the Buyer's Required Consents applicable to such Person and to make all required filings required to be made by it with, and to give all notices required to be given by it to, Governmental Authorities, and (ii) provide such other information and communications to such Governmental Authorities or other Persons as such Governmental Authorities or other Persons may reasonably request in connection therewith. Each Party agrees that it will accept the terms of all Permits as existing on the date of this Agreement (including the Environmental Permits) relating to the operation of the Acquired Assets, and shall not seek to amend any of such terms in connection with filings relating to the transactions contemplated by this Agreement, other than as necessary to effect the transfer of such Permits. Notwithstanding anything to the contrary in this Agreement, none of Buyer or its Affiliates shall be required to agree to take or refrain from taking any action in connection with a Seller's Required Consent or a Buyer's Required Consent that could reasonably be expected to result in a Burdensome Condition. Seller shall reasonably cooperate with Buyer in providing such notices to counterparties to Assigned Contracts as may be required by the terms of such Assigned Contracts or as Buyer (acting reasonably) may deem necessary, including notices providing counterparties with updated notice information and updated bank account information to which any applicable payments should be made by such counterparties.

(b) The Parties will provide prompt notification to each other when any such consent referred to in Section 5.2(a) is obtained, taken, made, given or denied, as applicable, and will, subject to Section 5.2(c), advise each other of any material communications with any Governmental Authority or other Person regarding any of the transactions contemplated by this Agreement.

(c) In furtherance of the foregoing covenants:

(i) Within two (2) Business Days following execution of this Agreement, Seller shall notify the Division as required by the Final Judgment and, as soon as is practical following the execution of this Agreement, Buyer shall prepare all necessary filings required to be made with the Federal Energy Regulatory Commission under Section 203 of the Federal Power Act, and each Party shall prepare all other necessary filings in connection with the transactions contemplated by this Agreement that may be required to be filed by such Party with applicable Governmental Authorities or under any applicable Laws. Except as set forth in the immediately preceding sentence, each Party shall submit such filings as soon as practicable, but in no event later than fifteen (15) days (subject to extension by mutual written agreement) after the execution hereof. The Parties shall take commercially reasonable efforts to respond to any questions or information requests of the Division and to comply with the timelines set forth in the

Final Judgment. The Parties shall request expedited treatment of any such filings (where applicable), promptly furnish each other with copies of any notices, correspondence or other written communication from the relevant Governmental Authority, promptly make any appropriate or necessary subsequent or supplemental filings, submissions or responses to any Governmental Authority, and cooperate in the preparation of such filings, submissions or responses as is reasonably necessary and appropriate. Subject to the last sentence in this Section 5.2(c)(i), (x) each Party shall have the right to review in advance all information related to Seller, the Facilities, the Acquired Assets or Buyer, as applicable, and the transactions contemplated by this Agreement with respect to any filing, submission or response with any Governmental Authority made by the other Party in connection with the transactions contemplated by this Agreement; (y) prior to the submission by Buyer of any filings to be made pursuant to this Section 5.2, Buyer shall provide to Seller a draft of each such filing, submission and response and reasonable opportunity to review and comment on each such filing; and (z) Buyer and Seller shall cooperate with each other to, and shall use reasonable efforts to, incorporate the other's comments into such filings. Notwithstanding the foregoing, neither Buyer nor Seller shall be obligated to share any information, filing, submission or responses with the other Party if a Governmental Authority objects to the sharing of such information, filings, submission or response.

(ii) Each Party will bear its own costs for the preparation of any filing.

(iii) The Parties shall not, and shall cause their respective Affiliates not to, take any action that would reasonably be expected to adversely affect or delay the approval of any Governmental Authority of any of the filings referred to in Section 5.2(c).

(iv) Seller shall, and shall cause its Affiliates that own or are counterparties to any Acquired Assets to, use best efforts to, and Buyer shall use commercially reasonable efforts to, secure the transfer or reissuance of the Permits (including the Transferred Permits), Emission Allowance compliance accounts for the Facilities, Seller's Required Consents and Buyer's Required Consents, effective as of the Closing Date. Each of Seller and Buyer shall cooperate with the other Party in this regard, and Seller shall use best efforts to, and Buyer shall use commercially reasonable efforts to, assist in such transfer or reissuance. If the Parties are unable to secure such transfer or reissuance effective on the Closing Date, the Parties shall continue to reasonably cooperate with the other Party's efforts to secure such transfer or reissuance following the Closing Date.

(d) The Parties hereto shall consult with each other prior to proposing or entering into any stipulation or agreement with any Governmental Authority or any third party whose consent is a Seller's Required Consent or a Buyer's Required Consent in connection with any Federal, State or local governmental consents and approvals legally required for the consummation of the transactions contemplated hereby, and shall not propose or enter into any such stipulation or agreement without the other Party's prior written consent, which consent shall not be unreasonably withheld.

Section 5.3 Access of Buyer and Seller.

(a) During the Interim Period, Seller will (i) provide Buyer and its Representatives with reasonable access, upon reasonable prior notice and during normal business hours, to all premises, properties, management, personnel, books, records (including Tax records) and documents associated with the Acquired Assets and permit Buyer and such Representatives to make such reasonable inspections thereof as Buyer may reasonably request (and Buyer shall be entitled, at its expense, to have the Sites surveyed and to conduct non-invasive physical inspections (which shall exclude any Phase I environmental site assessment)) provided, however, that Buyer shall not be entitled (A) to perform any Phase 1 environmental studies, or (B) to collect any air, soil, surface water or ground water samples nor to perform any invasive or destructive sampling on the Sites); (ii) subject to the receipt of any required consents and in accordance with applicable Laws, provide Buyer with such information and records (including payroll records) regarding Seller Employees and Off-Site Employees as Buyer reasonably deems necessary to comply with the obligations of this Agreement; (iii) furnish Buyer with a copy of each material report, schedule or other document filed or received by it or its Affiliates with respect to the Acquired Assets with a Governmental Authority. Notwithstanding the foregoing, and without limiting the generality of the confidentiality provisions set forth in Section 5.15, Seller shall not supply Buyer with any information or records if, and to the extent, prohibited by applicable Law.

(b) During the Interim Period, at the sole cost and expense of Buyer, Seller will permit designated employees or Representatives of Buyer (the "***Buyer's Observers***") to observe all operations of Seller related to the Acquired Assets, with such observation permitted on a cooperative basis in the presence of personnel of Seller during normal business hours of Seller; provided that (i) Buyer's Observers shall not unreasonably interfere with the operation of the Acquired Assets by Seller, and (ii) with respect to each such episode of observation, Buyer shall provide Seller with not less than two (2) Business Days' prior notice before any such observation shall be permitted.

(c) Buyer agrees to indemnify and hold harmless Seller, its Affiliates and their Representatives for any and all Loss incurred by Seller, its Affiliates or their Representatives to the extent arising out of any exercise of the access rights under this Section 5.3, including any Claims by any of Buyer's Representatives for any injuries or property damage while present at the Facilities, except in cases of Seller's or its Representatives' willful misconduct.

(d) For a period of seven (7) years after the Closing Date, Seller shall have reasonable access to, or at Buyer's option copies of, all of the records, books and documents related to the Acquired Assets of Buyer to the extent relating primarily to the Acquired Assets and relating to periods ending prior to the Closing Date and to the extent that such access may reasonably be required in connection with matters relating to the operations of Seller on or prior to the Closing Date (including liabilities with respect to Taxes); provided that Seller shall have the right, at its sole cost and expense, to retain copies of such records, books and documents, subject to its obligation to keep such information confidential in accordance with Section 5.15. Such access shall be afforded upon receipt of reasonable advance notice and during normal business hours. Seller shall be solely responsible for any costs or expenses incurred by it pursuant to this Section 5.3(d). If Buyer shall desire to dispose of any records, books or documents with respect to operation of the Acquired Assets before the Closing prior to the expiration of such seven-year period, Buyer shall, prior to such disposition, give to Seller a reasonable opportunity, at Seller's expense, to segregate and remove such records, books or documents as Seller may select. Notwithstanding anything contrary in this Agreement, in no event shall Seller or any of its Affiliates be required to provide access to, or copies of, any Tax Returns of Seller or any of its Affiliates.

(e) During the Interim Period, not less than two (2) Business Days prior to initiating contact or communication with any Governmental Authority or counterparty to any Assigned Contract, in each case with respect to which a Buyer's Required Consent or a Seller's Required Consent is required, Buyer shall provide Seller with (i) notice of such planned contact or communication and (ii) the opportunity to participate in such contact or communication; provided, for the avoidance of doubt, that where Seller does not elect to so participate, Buyer shall be free to proceed with such contact or communication without Seller's participation.

Section 5.4 Operation of Business. Except as set forth on **Schedule 5.4**, during the Interim Period, Seller will, and will cause its applicable Affiliates to, (1) operate and maintain the Acquired Assets (including maintaining the Permits and Material Contracts) in the ordinary course of business consistent with past practices and Good Utility Practice, and (2) use commercially reasonable efforts to complete the Budgeted Capital Expenditures in accordance with Good Utility Practice, unless otherwise expressly contemplated by this Agreement or with the prior written consent of Buyer (such consent not to be unreasonably withheld). Without limiting the generality of the foregoing, except as set forth on **Schedule 5.4**, Seller shall not, and shall cause its Affiliates not to, without the prior written consent of Buyer (which consent shall not be unreasonably withheld), during the Interim Period, with respect to the Acquired Assets and Assumed Liabilities:

(a) except for Acquired Assets used at or consumed by the Facilities in the ordinary course of business consistent with past practice and Good Utility Practice, (i) sell, lease (as lessor), license (as licensor), transfer or otherwise dispose of any of the Acquired Assets, or (ii) encumber, pledge, mortgage or suffer to be imposed on any of the Acquired Assets any Lien other than Permitted Liens;

(b) make any change in the levels of Fuel Inventory customarily maintained by Seller or its Affiliates with respect to the Acquired Assets, except for in the ordinary course of business consistent with past practice and Good Utility Practice, or purchase any Fuel Inventory which is not of a similar grade or type as purchased in the ordinary course of business consistent with past practice;

(c) except for any Permitted Contract, (i) enter into any Contract of a type described in Section 3.12(a), (ii) grant any waiver of any material term under, or give any material consent with respect to, any Material Contract, or (iii) terminate, enter into, amend or grant any waiver of any material term or give any material consent with respect to any Contract for the transmission of electricity or that relates to the purchase, sale or transportation of Fuel Inventory that relates to any period after the later of March 31, 2013 and Closing; provided that nothing in this clause shall inhibit the ability of Seller to terminate, amend or modify Contracts as required by Law; and provided further that during the Interim Period, **Schedules 2.1(f)** and/or **3.12**, as applicable, shall be amended to account for any Contract permitted under this Section 5.4(c);

(d) make any capital expenditures or enter into a Capital Commitment with respect thereto, except with respect to (i) capital expenditures or Capital Commitments necessitated by Good Utility Practice that do not exceed $5,000,000 in the aggregate, (ii) as may be necessitated by an emergency situation (in which case Seller shall promptly notify Buyer of such expenditure) or (iii) Budgeted Capital Expenditures; provided that, during the Interim Period, **Schedules 2.1(f)** and/or **3.12**, as applicable, shall be amended to account for any capital expenditure or Capital Commitment permitted under this Section 5.4(d);

(e) increase the level of wages, compensation or other benefits of any Seller Employees or Off-Site Employees (except for increases in salary or hourly wage rates in the ordinary course of business consistent with past practice or the payment of accrued or earned but unpaid bonuses);

(f) terminate the employment of any Seller Employee or Off-Site Employee except for cause, or hire any Seller Employee, in each case other than as consistent with past practice;

(g) enter into any collective bargaining agreement with respect to any Seller Employee or Off-Site Employee or enter into any employment agreement, severance, retention or bonus agreement or other Contract with or with respect to a Seller Employee or Off-Site Employee;

(h) incur, assume, guaranty or otherwise become liable in respect of any Indebtedness that could become an Assumed Liability;

(i) terminate, renew, amend, modify or replace any Permit, other than in the ordinary course of business consistent with past practices and Good Utility Practice and on terms and conditions that are not materially less favorable to any of the Facilities or the other Acquired Assets than under the Permit being so renewed;

(j) institute or settle any Claim that could become an Assumed Liability;

(k) otherwise take any action that will impede in any way the permitting, operation or contemplated divestiture to Buyer of the Acquired Assets;

(l) take any action that could reasonably be expected to adversely affect Seller’s queue position W3-122 with respect to the merchant transmission project; and

(m) agree or commit to do any of the foregoing.

Notwithstanding the foregoing, Seller may (A) to the extent required by applicable Law, and without Buyer’s prior written consent, take any action otherwise prohibited by this Section 5.4; provided, that Seller shall promptly inform Buyer upon taking any such action, and (B) enter into any agreement with any Seller Employee or Off-Site Employee who does not accept Buyer’s or its Affiliate’s offer of employment, provided that Buyer shall have no Liability under or with respect to any such agreement.

Section 5.5 Discharge of Business Obligations After Closing. From and after the Closing, (i) if Buyer or any of its Affiliates receives or collects any funds arising from or relating to the Excluded Assets, Buyer or its Affiliates shall remit such funds, to the extent arising from or relating to the Excluded Assets, to Seller within five (5) Business Days after its receipt thereof and (ii) if Seller or any of its Affiliates receives or collects any funds arising from or relating to the Acquired Assets, Seller or its Affiliates shall remit such funds, to the extent arising from or relating to the Acquired Assets, to Buyer within five (5) Business Days after its receipt thereof.

Section 5.6 Termination of Certain Services and Contracts. Notwithstanding anything in this Agreement to the contrary, at or prior to the Closing, Seller shall (a) terminate, effective upon or before the Closing, any services provided to any of the Facilities by Seller or an Affiliate thereof, including the termination or severance of insurance policies with respect to coverage for any of the Facilities (subject to Section 5.10), Tax services, legal services and banking services (to include the severance of any centralized clearance accounts), other than any such services provided pursuant to an Assigned Contract or the Transition Services Agreement and (b) terminate each Contract listed on **Schedule 5.6**, (collectively such services or Contracts, the "***Terminated Contracts***").

Section 5.7 Non-Use of Seller's Marks After the Closing.

(a) Buyer acknowledges and agrees that as a result of the consummation of the transactions contemplated by this Agreement, it will not obtain any right, title, interest, license or other right hereunder to use Seller's Marks, except to the extent permitted under Section 5.7(b) hereof.

(b) Buyer shall, within a reasonable period after the Closing Date not to exceed forty-five (45) days, remove Seller's Marks from, or cover or conceal Seller's Marks on, the Acquired Assets, including signage at the Facilities, to the extent Seller's Marks appear on the Acquired Assets; provided that Buyer shall, within three (3) Business Days after the Closing Date, remove, cover or conceal Seller's Marks that appear on signage at the primary entrances of the Facilities. Buyer may use Seller's Marks prior to such removal, cover, or concealment only to the extent they appear on the Acquired Assets. Nothing herein shall be deemed to prevent Buyer from referencing Seller's Marks as may be required by Law, including in a manner that constitutes "fair use", or in historical, Tax, and similar records.

Section 5.8 Real Property. Buyer shall have the right, at its cost and expense, to obtain new or updated title commitments of the Owned Real Property during the Interim Period, and new title insurance policies at Closing, and Seller shall reasonably cooperate with Buyer in connection with the foregoing.

Section 5.9 Employee and Benefit Matters

(a) Buyer or one of its Affiliates shall offer employment to each Seller Employee within forty-five (45) days after the execution of this Agreement, and in any event prior to Closing, and to each Off-Site Employee that it wishes to offer employment within sixty (60) days after the execution of this Agreement, and in any event prior to Closing. Each such offer to a Seller Employee shall include terms and provisions determined by Buyer or its Affiliate that are consistent with the provisions of this Section 5.9 (and may be conditioned upon the occurrence of the Closing and such individual's passage of any customary pre-employment background check and drug tests). Within sixty (60) days after the execution of this Agreement, and in any event prior to Closing, Buyer shall notify Seller as to each Seller Employee who has accepted employment with Buyer or any of its Affiliates and satisfied the applicable pre-hire requirements (each, a "***Transferred Employee***"), and each Seller Employee who has rejected Buyer's offer of employment or not satisfied such requirements. Each Transferred Employee shall cease to be employed by Seller as of such Transferred Employee's Hiring Time. Buyer shall indemnify and hold harmless Seller and its Affiliates with respect to all Liabilities arising out of Buyer's (or any of Buyer's Affiliates') actions or omissions with regard to employee selection and the employment offer process described in this Section 5.9(a) (including any claim of discrimination or other illegality in such selection and offer process, and including any Liability that Seller or any of its Affiliates may incur under the U.S. Worker Adjustment and Retraining Notification Act and the regulations promulgated thereunder, or any similar state or other Law as a result of any act or omission of Buyer occurring after the Closing). The employment with Buyer or an Affiliate of Buyer of each Transferred Employee shall be effective as of the Hiring Time and shall continue for at least two years thereafter; provided, however, that on such date such Transferred Employee is actively at work or is on an active employee status (and not designated as inactive or on short-term disability leave, long-term disability leave or on other leave). With respect to each Seller Employee who fails to become a Transferred Employee as of the Closing because he or she is on inactive status (including due to any short-term disability, long-term disability or other leave), Buyer shall, or shall cause its Affiliates to, at the time such Seller Employee is ready and available to return to active employment status (so long as such date occurs within 180 days after the Closing or such additional time required by Law), provide such Seller Employee with employment in a position comparable to that which the individual had prior to the commencement of his or her absence from active employment, which employment shall continue for at least two years thereafter (the Closing or such other time each Transferred Employee otherwise begins employment with Buyer or its Affiliate, as applicable, is referred to as his or her "***Hiring Time***"). During the two year period commencing at Closing, Buyer shall not permit a net reduction, due to involuntary attrition, in the employment levels at each Facility below the aggregate number of Transferred Employees employed by Buyer (or Buyer's Affiliates) immediately after the Closing. Nothing in the foregoing shall affect the right of Seller or Buyer (or Buyer's Affiliate) to terminate the employment of a Seller Employee for cause at any time.

(b) Except with respect to (i) Seller Employees as permitted under Section 5.9(a) and (ii) Off-Site Employees, unless the other Party should agree in writing, neither Seller nor Buyer will, directly or indirectly, in any manner whatsoever, solicit for employment any officer or employee of the other Party who Seller or Buyer learned of in connection with the acquisition contemplated hereby for a period of one year after the date of this Agreement; provided, however, that this sentence shall not apply to any solicitation (or any hiring as a result of any solicitation) that consists of advertising in a newspaper or periodical of general circulation or through the Internet, which advertising is not targeted at the officers or employees of the other Party.

(c) Except as set forth on **Schedule 5.9(c)**, effective as of their respective Hiring Times, Transferred Employees shall cease to participate in all Seller Employee Benefit Plans;

provided, however, that Seller or an Affiliate of Seller shall pay, in accordance with Seller's or such Affiliate's customary practice, to all Transferred Employees, all accrued salary or wages, including overtime, and all accrued incentive bonus, vacation pay or other employment benefits to which they are entitled under the Seller Benefit Plans as of their applicable Hiring Time. Neither Buyer nor any of its Affiliates shall assume or have any Liability with respect to any of the Seller Employee Benefit Plans.

(d) For the two (2) year period commencing on each Transferred Employee's Hiring Time, Buyer or an Affiliate of Buyer shall provide such Transferred Employee with (i) a base salary or wage rate that is not less than such Transferred Employee's base salary or wage rate that was in effect for such Transferred Employee immediately prior to such Transferred Employee's Hiring Time, and (ii) benefits and other compensation that are at least as favorable in the aggregate as the benefits and other compensation provided to such Transferred Employee immediately prior to such Transferred Employee's Hiring Time. Notwithstanding the foregoing, Buyer shall cause, or with respect to subsection (B) use commercially reasonable efforts to cause, each Transferred Employee and his or her eligible dependents (including all such Transferred Employee's dependents) covered immediately prior to the Closing by a group health plan maintained by Seller or an Affiliate of Seller to be covered under a group health plan maintained by Buyer or an Affiliate of Buyer that (A) provides major medical and dental benefits coverages to the Transferred Employee and such eligible dependents effective immediately upon the Hiring Time and (B) credits such Transferred Employee, for the year during which such coverage under such group health plan begins, with any deductibles and co-payments already incurred during such year under a group health plan maintained by Seller or an Affiliate of Seller; provided, however, that for purposes of applying this clause (B) with respect to any Transferred Employee, the Transferred Employee shall be responsible for providing the necessary information to Buyer based on explanation of benefit forms received by the Transferred Employee from the group health plan maintained by Seller or an Affiliate of Seller. Buyer or an Affiliate of Buyer shall recognize each Transferred Employee's years of company service prior to the applicable Hiring Time with Seller and its Affiliates for purposes of vesting or other benefit/coverage eligibility (including eligibility for retiree benefits/coverages), benefit accrual (with the exception of benefits accrued pursuant to any Buyer or Buyer Affiliate "defined benefit pension plan" as defined in ERISA Section 3(35)), and benefit determination under all employee benefit and compensation plans and programs maintained after the applicable Hiring Time by Buyer or an Affiliate of Buyer in which such Transferred Employee is permitted to participate, including paid vacation, paid sick time and severance benefits. Buyer shall cause each employee welfare benefit plan or program sponsored by Buyer or an Affiliate of Buyer that the Transferred Employees may be eligible to participate in on or after the Closing to waive any preexisting condition exclusion or restriction with respect to participation and coverage requirements applicable to Transferred Employees. Nothing in the foregoing shall affect the right of Buyer or its Affiliate to terminate the employment of a Transferred Employee for cause at any time, and notwithstanding the foregoing, Buyer shall thereafter have no obligation with respect to any payments, compensation or benefits to such terminated Transferred Employee except as otherwise required by Law.

(e) Claims of Transferred Employees and their eligible beneficiaries and dependents for medical, dental, prescription drug, life insurance or other welfare benefits ("***Welfare Benefits***") (other than disability benefits) that are incurred before a Transferred Employee's

Hiring Time shall be the sole responsibility of Seller. Claims of Transferred Employees and their eligible beneficiaries and dependents for Welfare Benefits (including disability benefits) that are incurred from and after a Transferred Employee's Hiring Time shall be the sole responsibility of Buyer and its Affiliates. For purposes of this paragraph, a medical/dental claim shall be considered incurred on the date when the medical/dental services are rendered or medical/dental supplies are provided, and not when the condition arose or when the course of treatment began.

(f) All claims for health care and dependent care flexible spending account benefits submitted after the Closing Date for expenses incurred prior to a Transferred Employee's Hiring Time by Transferred Employees shall be paid by Seller's health care and dependent care flexible spending account plan to the extent permitted in accordance with the terms of such plan.

(g) Claims for workers' compensation benefits by or on behalf of Transferred Employees arising out of occurrences prior to a Transferred Employee's Hiring Time shall be the responsibility of Seller. Claims for workers' compensation benefits by or on behalf of Transferred Employees arising out of occurrences on or after a Transferred Employee's Hiring Time shall be the responsibility of Buyer.

(h) Nothing herein shall be deemed or construed to (i) give rise to any rights, claims, benefits, or causes of action to a Seller Employee or Off-Site Employee or make any Seller Employee or Off-Site Employee a third-party beneficiary hereof, or (ii) prevent, restrict, or limit Seller, Seller's Affiliates, Buyer or Buyer's Affiliates, following the Closing Date, from modifying or terminating any of its benefit plans, programs or policies from time to time as it may deem appropriate, subject only to compliance with the express provisions of this Section 5.9.

(i) From and after the Closing Date, Buyer shall provide, or shall cause any successor to Buyer to provide, to Seller, once per year, reports setting forth (i) the name, birth date, and last four digits of the Social Security Number of each Transferred Employee and each Off-Site Employee who has accepted employment with Buyer or any of its Affiliates, (ii) whether each such Transferred Employee or Off-Site Employee who has accepted employment with Buyer or any of its Affiliates is as of the date of such report employed by Buyer or any of its Affiliates or any successor thereof and (iii) if any such Transferred Employee or Off-Site Employee who has accepted employment with Buyer or any of its Affiliates is not, as of the date of such report, so employed, the date of termination of such Transferred Employee's or Off-Site Employee's who has accepted employment with Buyer or any of its Affiliates employment by Buyer or any of its Affiliates or any successor thereof. The foregoing requirement of the frequency of such reports notwithstanding, upon Seller's reasonable request (no more frequently than four times per calendar year), Buyer shall promptly provide to Seller the information described in clauses (i) through (iii) of this Section 5.9(i) with respect to any Transferred Employee or Off-Site Employee who has accepted employment with Buyer or any of its Affiliates with respect to whom Seller so requests such information.

(j) To the extent permitted by applicable Law, Seller shall provide Buyer or its designated Affiliate with those personnel and other records relating to Transferred Employees who become employees of Buyer or its Affiliates.

(k) Buyer shall have the right to designate its obligations to make offers of employment pursuant to this Section 5.9 to an Affiliate or a third party designee; provided that such third party designee shall be obligated to comply with the provisions of this Section 5.9 and such designation shall not release Buyer from any of its obligations under this Section 5.9.

Section 5.10 Insurance. Seller shall maintain or cause to be maintained in full force and effect the insurance policies described on **Schedule 3.13** until the Closing.

Section 5.11 Transfer Taxes. Notwithstanding any other provision of this Agreement, all Transfer Taxes that may be imposed upon, or payable, collectible or incurred in connection with the transfer of the Acquired Assets to Buyer or otherwise as a result of the transfer of the Acquired Assets hereunder shall be borne 50% by Buyer and 50% by Seller. Buyer, at its own expense, will complete, to the extent required by applicable Law, all necessary Tax Returns and other documentation with respect to all such Transfer Taxes, and if required by applicable Law, Seller will join in the execution of any such Tax Returns or other documentation. Buyer and Seller shall each take commercially reasonable steps and make all necessary filings in order to minimize such Transfer Taxes. Prior to Buyer filing all necessary Tax Returns and other documentation with respect to all such Transfer Taxes, Buyer shall provide such Tax Returns to Seller and Seller shall have up to ten (10) Business Days to review and comment on such Tax Returns. All necessary Tax Returns and other documentation with respect to all such Transfer Taxes shall be subject to Seller's approval. Upon receipt of Seller's approval or if Seller does not provide any comments within ten (10) days, Buyer may file all necessary Tax Returns and other documentation with respect to all such Transfer Taxes. With respect to each Transfer Tax, the party liable for the Transfer Tax under applicable Law shall timely remit, or cause to be timely remitted, such Transfer Tax to the appropriate Taxing Authority and the other Party shall promptly reimburse the remitting Party for its share of such Transfer Tax.

Section 5.12 Tax Matters. Except as provided in Section 5.11 relating to Transfer Taxes:

(a) With respect to Taxes to be prorated in accordance with Section 2.10 of this Agreement, Buyer shall prepare and timely file all Tax Returns required to be filed after the Closing with respect to the Acquired Assets, if any, and Buyer shall duly and timely pay all such Taxes shown to be due on such Tax Returns (or shall reimburse Seller for any such Taxes paid by Seller). Buyer's preparation of any such Tax Returns shall be subject to Seller's review and comment, and Buyer shall consider in good faith any comments received from Seller. No later than ten (10) Business Days prior to the due date of any such Tax Return, Buyer shall make such Tax Return available for Seller's review and comment. Buyer shall respond no later than five (5) Business Days prior to the due date for filing such Tax Return. Without the prior written consent of Seller, Buyer will not (i) file or amend any Tax Return relating to a taxable period (or portion thereof) ending on or prior to the Closing Date or (ii) extend or waive, or cause to be extended or waived, any statute of limitations or other period for the assessment of any Tax or deficiency related to a taxable period (or portion thereof) ending on or prior to the Closing Date; provided, however, that Buyer may amend any such return if Buyer agrees not to seek indemnity from Seller for, and to indemnify and hold Seller harmless against, any Taxes or Losses attributable to such amended return.

(b) Whenever any Taxing Authority asserts a claim, makes an assessment, or otherwise disputes the amount of Taxes relating to a taxable period (or portion thereof) ending on or before the Closing Date, Buyer shall, upon receipt of such assertion, promptly, but no later than thirty (30) days thereafter, inform Seller in writing of such assertion. With respect to proceedings that relate solely to Taxes that the Buyer acknowledges in writing represent Excluded Liabilities, Seller shall have the sole right to control any such proceedings and to determine whether and when to settle any such claim, assessment or dispute; provided, however, that Seller shall not settle any Tax controversies in a manner that would reasonably be expected to affect the Tax liabilities of Buyer or any of its Affiliates in a material manner for any taxable year or period ending after the Closing Date without the prior written consent of Buyer. With respect to proceedings that relate to Taxes for which the Buyer does not acknowledge in writing represent Excluded Liabilities, Buyer shall have the sole right to control any such proceedings and determine whether and when to settle any such claim, assessment or dispute; provided, however, that Buyer shall not settle any Tax controversies in a manner that would reasonably be expected to affect the Tax liabilities of Seller or any of its Affiliates in a material manner for any taxable year or period without the prior written consent of Seller. Each of Buyer and Seller shall provide the other with such assistance and cooperation as may reasonably be requested by the other Party in connection with the preparation of any Tax Return, any audit or other examination by any Taxing Authority, or any judicial or administrative proceedings relating to liability for Taxes. Such assistance and cooperation shall include the retention and (upon the other Party's request) the provision of records and information that are reasonably relevant to any such audit, litigation or other proceeding and making employees available on a mutually convenient basis to provide additional information and explanation of any material provided hereunder, and each will retain and provide the requesting Party with any records or information until the expiration of the statute of limitations (and, to the extent notified by the other Party, any extensions thereof) of the respective taxable periods which may be relevant to such Tax Return, audit or examination, proceedings or determination.

Section 5.13 Casualty. If any Acquired Asset is damaged or destroyed by a casualty loss after the Effective Date and prior to the Closing (a "***Casualty Loss***"), and the cost of restoring such damaged or destroyed Acquired Asset to a condition reasonably comparable to its prior condition, (such costs with respect to any Acquired Asset, the "***Casualty Cost***") is greater than $1,500,000 but less than or equal to 20% of the Base Purchase Price, Seller shall elect, by notice to Buyer provided within fifteen (15) days of the applicable Casualty Loss, to either (i) reduce the amount of the Purchase Price by the estimated Restoration Cost (as estimated by a qualified firm mutually selected by Buyer and Seller promptly after the date of the event giving rise to the Casualty Loss) or (ii) restore such damaged or destroyed Acquired Asset at Seller's expense prior to Closing to a condition reasonably comparable to its condition prior to such Casualty Loss, and in either event such Casualty Loss shall not affect the Closing. If the aggregate Casualty Cost associated with all Casualty Losses is greater than 20% of the Base Purchase Price, then either Buyer or Seller may terminate this Agreement pursuant to Section 8.1(e) hereof. If the Casualty Cost is equal to or less than $1,500,000 of the Base Purchase Price, (x) neither Buyer nor Seller shall have the right or option to terminate this Agreement and (y) there shall be no reduction in the amount of the Purchase Price. To the extent Seller elects to reduce the amount of the Purchase Price by the estimated Restoration Cost pursuant to this Section 5.13, Buyer will, at Seller's written election, assign to Seller the rights if any, to any contribution available under any long term service agreement, as and to the extent relating to the applicable Casualty Loss. "***Restoration Cost***" means, with respect to a Casualty Loss, the sum of (a) the Casualty Cost with respect to such Casualty Loss, plus (b) the amount of gross margin with respect to such Casualty Loss; in each case arising after the Closing Date and as determined by a qualified firm mutually selected by Buyer and Seller promptly after the date of the event giving rise to such Casualty Loss, which firm shall take into account, among other things, a reasonable period that the firm estimates the damaged or destroyed Acquired Assets will remain unrestored under Good Utility Practice.

Section 5.14 Condemnation. If any Acquired Asset is taken by condemnation after the date hereof and prior to the Closing and such Acquired Asset has a Condemnation Value which is greater than $1,500,000 but less than or equal to 20% of the Base Purchase Price, Seller shall elect by written notice to Buyer provided within fifteen (15) days of the applicable condemnation event (and in any event at least ten (10) days prior to the Closing Date) to reduce the Purchase Price by such Condemnation Value and such condemnation shall not affect the Closing. If the aggregate Condemnation Values associated with all such condemnation events is greater than 20% of the Base Purchase Price, either Buyer or Seller may terminate this Agreement pursuant to Section 8.1(e) hereof. If the Condemnation Value is equal to or less than $1,500,000 of the Base Purchase Price, (x) neither Buyer nor Seller shall have the right or option to terminate this Agreement, and (y) there shall be no reduction in the amount of the Purchase Price. "***Condemnation Value***" shall mean an amount equal to the condemnation award value of the affected Acquired Asset plus, if not otherwise included in the condemnation award value, the amount of any gross margin with respect to such affected Acquired Assets which results from such condemnation, with such gross margin determined by a qualified firm mutually selected by Buyer and Seller promptly after the date of the event giving rise to such condemnation.

Section 5.15 Confidentiality.

(a) Any information or materials furnished by Seller or any of its Affiliates to Buyer on and after the date of this Agreement and prior to Closing shall be subject to the Confidentiality Agreement; provided that Buyer shall not have any obligation to maintain the confidentiality of information with respect to the Acquired Assets from and after the Closing. Notwithstanding the foregoing, Buyer and its Affiliates shall be entitled to disclose Confidential Information to investors and limited partners, and to prospective investors or other Persons as part of fundraising, financing or marketing activities undertaken by Buyer or its Affiliates, provided such disclosures are made to Persons subject to an obligation of confidentiality with respect to such information. Effective upon Closing, the Parties shall cause the Confidentiality Agreement to be terminated. In the event of any conflict between this Agreement and the Confidentiality Agreement, this Agreement shall prevail.

(b) Either Party may provide Confidential Information to any Governmental Authority with jurisdiction as necessary to comply with Section 5.2. To the extent permitted by Law, the disclosing Party shall exercise commercially reasonable efforts to seek confidential treatment for the Confidential Information provided to any Governmental Authority and the disclosing Party shall notify the other Party as far in advance as is practicable and lawful of its intention to release to any Governmental Authority any Confidential Information.

(c) From and after Closing, Seller shall, and shall cause its Affiliates to, maintain in confidence and not disclose to any Person any Confidential Information (except for Confidential Information relating exclusively to Seller and its Affiliates, and not to any of the Acquired Assets or Assumed Liabilities) or any non-public information relating to Buyer or its Affiliates provided in connection herewith, except as and to the extent required by Law or this Agreement or any of the Ancillary Agreements.

(d) The obligations of the Parties in this Section 5.15 will survive the termination of this Agreement and the Closing.

Section 5.16 Public Announcements. Except as required by Law or by the rules of a national securities exchange to make such disclosure, each Party shall, and shall cause its Affiliates (as applicable), to consult with the other Party regarding the timing and content of all public announcements regarding this Agreement, the Closing and the other transactions contemplated by this Agreement to the financial community, any Governmental Authority, customers, suppliers or the general public; provided that, Buyer and Seller shall not, and shall cause their respective Affiliates to not, make any such public announcement without the prior written consent of the other Party.

Section 5.17 Environmental Permits. From and after the Closing, Seller shall not undertake, directly or indirectly, any challenges to the Permits (including the Environmental Permits) relating to the operation of the Acquired Assets. No later than thirty (30) days prior to the Closing Date, Seller shall provide to Buyer an executed notice, in substantially the form attached hereto as **Exhibit G**, regarding the Maryland Department of the Environment solid waste permit referenced therein, and Seller shall provide a copy of such notice to the Maryland Department of the Environment. During the Interim Period, Seller shall, or shall cause the Acquired Entity to, diligently prosecute the application for the Lot 15 Solid Waste Permit in the name of the Acquired Entity.

Section 5.18 Joint Defense Agreement. As promptly as practicable after the Effective Date, Buyer and Seller shall enter into a joint defense agreement with respect to all filings required to be made with any Governmental Authority hereunder in connection with the transactions contemplated by this Agreement, in form and substance satisfactory to Buyer and Seller.

Section 5.19 Support Obligations. Prior to the Closing Date, Seller and Buyer shall cooperate to, and shall each use commercially reasonable efforts to, terminate, or cause Buyer to be substituted in all respects for Seller and any of Seller's Affiliates in respect of all obligations of Seller and any of its Affiliates under all Support Obligations (other than those Support Obligations that relate to Permits or Material Contracts that are not transferred to Buyer (or its designee) as of Closing). With respect to any Coal Support Obligation that remains outstanding after the Closing Date (until such time as such Coal Support Obligation is terminated or substituted in accordance herewith, an "***Outstanding Coal Support Obligation***"), (a) Buyer shall continue to use its commercially reasonable efforts to terminate, or cause Buyer to be substituted in all respects for Seller and any of its Affiliates in respect of, all obligations of Seller or any of its Affiliates under such Outstanding Coal Support Obligations; (b) Buyer shall not renew, amend or extend the terms of (in any manner that increases or extends or otherwise adversely changes the obligations of Seller or any of Seller's Affiliates under) any Contract or other obligation for which Seller or any of its Affiliates is or would reasonably be expected to be liable under, any such Outstanding Coal Support Obligations unless Seller and all of Seller's Affiliates are completely released from all Support Obligations and other liability under such Contracts; and (c) Seller shall and, if applicable, shall cause its Affiliates to, maintain each such Outstanding Coal Support Obligation until (1) its termination in accordance with its terms, (2) substitution has been effected or (3) its termination in accordance with the immediately succeeding sentence. After Closing, if a draw occurs under an Outstanding Coal Support Obligation as the result of an event of default by Buyer or its Affiliates, and Seller (or Seller's Affiliate, as applicable) pays an amount equal to or greater than $500,000 in connection therewith, then Seller (or Seller's Affiliate, as applicable) shall be entitled to terminate such Outstanding Coal Support Obligation upon at least five (5) Business Days' prior written notice to Buyer; provided, that all applicable notice and cure periods under the Contract to which such Outstanding Coal Support Obligation relates shall have expired; provided further, that Buyer shall not have reimbursed Seller (or Seller's Affiliate, as applicable) for such payment. The provisions of this Agreement notwithstanding, in no event shall any Outstanding Coal Support Obligation remain outstanding after the termination of the underlying Contract relating to such Outstanding Coal Support Obligation, and Seller (or Seller's Affiliate, as applicable) may terminate any such Outstanding Coal Support Obligation as of the date of such termination of such Contract.

Section 5.20 500 MW Commitment. Buyer shall not, and shall cause its Affiliates not to, purchase any electricity or energy offered by Seller or its Affiliates pursuant to or as a result of the 500 MW Commitment.

Section 5.21 RGGI Compliance. Within thirty (30) days of Seller's receipt of all United States Environmental Protection Agency Emission Collection and Monitoring Plan System feedback reports and submission receipts for the quarterly electronic data reports for emissions from the Facilities for the period commencing on January 1, 2012 and ending on the Closing Date, Seller shall transfer to Buyer or an Affiliate of Buyer such Regional Greenhouse Gas Initiative emissions allowances ("***RGGI Allowances***") as shall be necessary to equal the carbon dioxide emissions from the Facilities for such period.

Section 5.22 Further Assurances.

(a) At any time and from time to time after the Closing, at the reasonable request of a Party and without further consideration, the other Party will or will cause its Affiliates to execute and deliver such instruments of sale, transfer, conveyance, assignment and confirmation and take such actions as may be necessary to transfer, convey and assign to Buyer or its designee, and to confirm Buyer's or its designee's title to or interest in the Acquired Assets and Assumed Liabilities or to put Buyer or its designee in actual possession and operating control of the Acquired Assets, and otherwise to consummate and give effect to the transactions contemplated by this Agreement; provided, however, that no such instrument or action shall increase Buyer's liability or decrease Buyer's rights, under this Agreement.

(b) In the event that any asset that is an Acquired Asset shall not have been conveyed to Buyer or its designee at the Closing, Seller shall (or shall cause its Affiliates to), subject to Section 5.22(c), use its commercially reasonable efforts to convey such asset to Buyer or its designee as promptly as is practicable after the Closing.

(c) To the extent that Seller’s or any of its Affiliate’s rights under any Contract may not be assigned without the consent of another Person which consent has not been obtained by the Closing, this Agreement shall not constitute an agreement to assign the same if an attempted assignment would constitute a breach thereof or be unlawful, and Seller and Buyer shall cooperate and shall each use their commercially reasonable efforts to obtain any such required consent(s) as promptly as possible. Seller and Buyer agree that if any consent to an assignment shall not be obtained, or if any attempted assignment would be ineffective or would impair Buyer’s rights and obligations under the Contract in question, so that Buyer (or its designee) would not in effect acquire the benefit and burden of all such rights and obligations, Seller (or its applicable Affiliate), to the maximum extent permitted by law and such Contract, shall from and after the Closing, appoint Buyer (or its designee) to be Seller’s (or its applicable Affiliate’s) agent with respect to such Contract and Seller shall (and shall cause its Affiliates), to the maximum extent permitted by law and such Contract, enter into such reasonable arrangements with Buyer (or its designee) as are reasonably satisfactory to Buyer and necessary to provide Buyer (or its designee) with the benefits and obligations of such Contract (other than any Excluded Liability and other than obligations for which Seller indemnifies any Buyer Indemnified Party pursuant to this Agreement). Seller and Buyer shall cooperate after the Closing and shall each use their commercially reasonable efforts after the Closing to obtain an assignment of such Contract. From and after Closing, Seller shall hold (and shall cause its Affiliates to hold) in trust for, and pay to, Buyer or its designee) promptly upon receipt thereof, all income, proceeds, and other monies received by Seller or its Affiliates in respect of Buyer’s (or its designees) performance of any Assigned Contract in connection with the arrangements under this Section 5.22 or any other Acquired Assets.

Section 5.23 Monthly Operating Report. During the Interim Period, on or prior to thirty (30) days following the end of each calendar month, Seller shall provide Buyer with a monthly operating report with respect to each Facility prepared in the ordinary course of business consistent with past practice.

Section 5.24 C.P. Crane Facility Remediation. During the Interim Period, Seller shall diligently and timely respond to and address all requests by the Maryland Department of Environment stated in the letter dated June 29, 2012 regarding the ongoing Remediation project (Maryland Department of Environment Oil Control Program Case No. 8-1361BA) at the C.P. Crane Facility. During the Interim Period, Seller shall diligently pursue regulatory closure of the Environmental Condition at the C.P. Crane Facility that is the subject of Maryland Department of Environment Oil Control Program Case No. 801361BA as directed by the Maryland Department of Environment.

Section 5.25 Emission Allowances. Prior to the Closing Date, Seller shall and shall cause its Affiliates to transfer all Emission Allowances identified in **Schedule 2.1(l)** and any additional Emission Allowances that are granted or issued to the Facilities before the Closing Date into the corresponding compliance accounts for the Brandon Shores Facility, C.P. Crane Facility, or H.A. Wagner Facility.

Section 5.26 Specified Capacity.

(a) Seller shall bid, in the First Incremental PJM Auction for the 2014/2015 Delivery Year (the "***First Auction***"), which is scheduled to close on September 14, 2012, available capacity from the Facilities in the following quantities from the following units: 21.5 MW from Unit 2 of the Brandon Shores Facility, 163.7 MW from Unit 1 of the C.P. Crane Facility, 171.5 MW from Unit 2 of the C.P. Crane Facility, 1.0 MW from Unit 3 of the C.P. Crane Facility, 12.0 MW from Unit 1 of the H.A. Wagner Facility, 130.0 MW from Unit 2 of the H.A. Wagner Facility, 283.3 MW from Unit 3 of the H.A. Wagner Facility, 3.7 MW from Unit 4 of the H.A. Wagner Facility, and 9.9 MW from Unit 5 of the H.A. Wagner Facility (such available capacity, collectively, the "***Specified Available Capacity***").

(b) Both Seller and Buyer shall, and shall cause their Affiliates, as applicable, to, bid in each PJM Auction for the 2014/2015 Delivery Year in accordance with PJM rules. With respect to any portion of the Specified Available Capacity that does not clear in the First Auction (such uncleared capacity, the "***First Remainder Uncleared Capacity***"), whichever Party owns the Facilities at the time of the Second Incremental PJM Auction for the 2014/2015 Delivery Year (the "***Second Auction***"), which is scheduled to close on July 19, 2013, shall bid the First Remainder Uncleared Capacity in the Second Auction. With respect to any portion of the First Remainder Uncleared Capacity that does not clear in the Second Auction (such uncleared capacity, the "***Second Remainder Uncleared Capacity***"), whichever Party owns the Facilities at the time of the Third Incremental PJM Auction for the 2014/2015 Delivery Year (the "***Third Auction***"), which is scheduled to close on February 28, 2014, shall bid the Second Remainder Uncleared Capacity in the Third Auction. Any portion of the Specified Available Capacity that does not clear any of the First Auction, the Second Auction or the Third Auction is referred to herein as the "***Final Remainder Capacity***." All portions of the Specified Available Capacity that clear in any of the First Auction, the Second Auction or the Third Auction are referred to herein as the "***Specified Cleared Capacity***." The applicable price (measured in dollars per MW-day) at which each portion of the Specified Cleared Capacity clears the applicable auction is referred to herein as the "***Applicable Clearing Price***." During the Interim Period, Schedules 2.1(f) and/or 3.12, as applicable, shall be amended to account for the Specified Cleared Capacity.

(c) On the last day of each of the fifty-two (52) weeks that compose the 2014/2015 Delivery Year, and with respect to each applicable portion of the Specified Available Capacity for such week that together constitute the Specified Cleared Capacity, Seller shall pay to Buyer (or its designee) an amount equal to (i) such applicable portion of the Specified Cleared Capacity, times (ii) the difference between $125.99/MW-day and the Applicable Clearing Price for such applicable portion of the Specified Cleared Capacity (such difference, the "***Price Differential***"), times (iii) the number of days in the applicable payment period; provided that if the Price Differential is a negative number, Buyer shall pay to Seller an amount equal to (A) such applicable portion of the Specified Cleared Capacity, times (B) the absolute value of the Price Differential, times (C) the number of days in the applicable payment period.

(d) In the event that there is Final Remainder Capacity following the close of the Third Auction, Seller shall on the last day of each of the fifty-two (52) weeks that compose the 2014/2015 Delivery Year, pay to Buyer (or its designee) an amount equal to (i) the Final Remainder Capacity times (ii) the number of days in the applicable payment period times (iii) $125.99/MW-day.

ARTICLE VI
BUYER'S CONDITIONS TO CLOSING

The obligation of Buyer to consummate the Closing is subject to the fulfillment of each of the following conditions (except to the extent waived in writing by Buyer):

Section 6.1 Representations and Warranties. The representations and warranties set forth in Article III other than the representations set forth in the last sentence of this Section 6.1 (disregarding for purpose of this Section 6.1 any qualifications with respect to materiality or Material Adverse Effect) shall be true and correct on the Closing Date as though made on the Closing Date (other than representations and warranties that address matters only as of a certain date which shall be true and correct as of such certain date), except for any failures to be true and correct which would not have a Material Adverse Effect. The representations and warranties set forth in the first sentence of Section 3.18(b), the Designated Representations (other than those representations and warranties set forth in Section 3.5(a)) and the representations and warranties set forth in Section 3.23(c) shall be true and correct in all material respects on the Closing Date as though made on the Closing Date.

Section 6.2 Performance. Seller shall have performed and complied, in all material respects, with all agreements, covenants and obligations required by this Agreement to be performed or complied with by Seller at or before the Closing.

Section 6.3 Officer's Certificate. Seller shall have delivered to Buyer at the Closing a certificate of an officer of Seller, dated as of the Closing Date, as to the matters set forth in Sections 6.1 and 6.2.

Section 6.4 Deliveries. Seller shall have complied with the delivery requirements of Section 2.7.

Section 6.5 Required Consents. Seller's Required Consents and Buyer's Required Consents shall have been duly obtained, made or given and shall be in full force and effect, and shall not reasonably be expected to in the aggregate impose a Burdensome Condition; and all terminations or expirations of waiting periods imposed by any Governmental Authority with respect thereto shall have occurred; provided, however, that the absence of any appeals and the expiration of any appeal period with respect to any of the foregoing shall not constitute a condition to Closing hereunder.

Section 6.6 Litigation. There shall not be any injunction, judgment, order, decree or ruling in effect that would materially adversely prevent consummation of the transactions contemplated by this Agreement or the Ancillary Agreements.

Section 6.7 Liens. Seller shall have delivered to Buyer at Closing payoff letters with respect to all Indebtedness (including Tax exempt Indebtedness) of Seller or its Affiliates relating to any of the Acquired Assets evidencing that all such Indebtedness shall be (or shall have been) paid in full and Buyer shall have received evidence that all Liens on any of the Acquired Assets (other than Permitted Liens) have been released prior to or concurrently with Closing.

ARTICLE VII
SELLER'S CONDITIONS TO CLOSING

The obligation of Seller to consummate the Closing is subject to the fulfillment of each of the following conditions (except to the extent waived in writing by Seller):

Section 7.1 Representations and Warranties. The representations and warranties set forth in Article IV that are not qualified by materiality or material adverse effect shall be true and correct in all material respects, and all other representations and warranties that are so qualified shall be true and correct in all respects, in each case at and as of the Closing Date, except where the failure to be true and correct would not reasonably be expected to have a material adverse effect on the ability of Buyer to consummate the transactions contemplated hereby.

Section 7.2 Performance. Buyer shall have performed and complied, in all material respects, with all agreements, covenants and obligations required by this Agreement to be so performed or complied with by Buyer at or before the Closing.

Section 7.3 Officer's Certificate. Buyer shall have delivered to Seller at the Closing a certificate of an officer of Buyer, dated as of the Closing Date, as to the matters set forth in Sections 7.1 and 7.2.

Section 7.4 Deliveries. Buyer shall have complied with the delivery requirements of Section 2.8.

Section 7.5 Required Consents. Seller's Required Consents shall have been duly obtained, made or given and shall be in full force and effect, and all terminations or expirations of waiting periods imposed by any Governmental Authority with respect thereto shall have occurred; provided, however, that the absence of any appeals and the expiration of any appeal period with respect to any of the foregoing shall not constitute a condition to Closing hereunder.

Section 7.6 Litigation. There shall not be any injunction, judgment, order, decree or ruling in effect that would materially adversely prevent consummation of the transactions contemplated by this Agreement or the Ancillary Agreements.

Section 7.7 Release of Support Obligations. The termination of, or substitution of Buyer in respect of, Seller's and Seller's Affiliates' obligations under the Support Obligations other than the Coal Support Obligations shall have been effected in accordance with Section 5.19.

ARTICLE VIII
TERMINATION

Section 8.1 Termination. This Agreement may be terminated, and the transactions contemplated hereby may be abandoned, at any time before the Closing as follows:

(a) by Seller or Buyer, by written notice to the other, if (i) any Law or final order restrains, enjoins or otherwise prohibits or makes illegal the transactions contemplated pursuant to this Agreement, or (ii) any application for a Seller's Required Consent or Buyer's Required Consent where the counterparty is a Governmental Authority is denied by the applicable Governmental Authority;

(b) by Seller, by written notice to Buyer, if (i) Buyer has breached any representation, warranty, covenant, agreement or obligation in this Agreement, (ii) such breach results in, or would reasonably be expected to result in, the failure of any condition expressly set forth in Article VII, and (iii) such breach has not been cured within thirty (30) days following written notification thereof; provided, however, that if, at the end of such thirty (30) day period, Buyer is endeavoring in good faith, and proceeding diligently, to cure such breach, Buyer shall have an additional thirty (30) days in which to effect such cure;

(c) by Buyer, by written notice to Seller, if Seller has breached in any material respect any representation, warranty, covenant, agreement or obligation in this Agreement and such breach has not been cured within thirty (30) days following written notification thereof; provided, however, that if, at the end of such thirty (30) day period, Seller is endeavoring in good faith, and proceeding diligently, to cure such breach, Seller shall have an additional thirty (30) days in which to effect such cure;

(d) by Buyer or Seller on or after the date that is one hundred twenty (120) days (or, in the event that all conditions to Closing (other than those that by their nature are to be satisfied or waived at Closing) have been satisfied or waived, as applicable, other than the obtaining of a Seller's Required Consent or Buyer's Required Consent where the counterparty is a Governmental Authority, one hundred eighty (180) days) after the date of this Agreement, in each case by notice to the other, or such later date as Buyer and Seller may agree in writing; provided, that Buyer cannot terminate under this provision if the failure of the Closing to occur is the result of the failure on the part of Buyer to perform any of its obligations hereunder and Seller cannot terminate this Agreement under this provision if the failure of the Closing to occur is the result of the failure on the part of Seller to perform any of its obligations hereunder;

(e) by Buyer or Seller in accordance with Section 5.13 or 5.14;

(f) by mutual written consent of Buyer and Seller; and

(g) by Buyer upon payment of the fee specified in Section 8.4(a).

Section 8.2 Effect of Termination.

(a) If this Agreement is validly terminated pursuant to Section 8.1, there will be no liability or obligation on the part of Seller or Buyer (or any of their respective Representatives or Affiliates), except as provided in this Section 8.2 or Section 8.4; provided that nothing in this Section 8.2(a) shall relieve any Party from liability for any breach of this Agreement by such Party prior to termination of this Agreement.

(b) Regardless of the reason for termination, Sections 5.3(c), 5.15, 5.16 and 8.2 and Article X will survive any termination of this Agreement.

(c) Upon termination of this Agreement by either Party for any reason, each Party shall return or destroy, in accordance with and to the extent required by the terms of the Confidentiality Agreement, all Confidential Information and all other documents and other materials of any other Party relating to the Acquired Assets, the Facilities, the Sites, Seller or this Agreement and the transactions contemplated hereby, including any information relating to the Parties and to this Agreement, whether obtained before or after the execution of this Agreement (collectively, the "***Transaction Materials***") and all Transaction Materials received by Buyer with respect to the Acquired Assets, the Facilities, the Sites or Seller shall remain subject to the Confidentiality Agreement; provided, that if any action, lawsuit or claim is initiated or filed within one year after the date of this Agreement by a Party with respect to the termination of this Agreement pursuant to this Article XIII, the Parties shall not be required to return or destroy the Transaction Materials pursuant to this Section 8.2(c) or the Confidentiality Agreement until such action, lawsuit or claim is resolved, dismissed or withdrawn.

Section 8.3 Specific Performance and Other Remedies. Each Party hereby acknowledges that the rights of each Party to consummate the transactions contemplated hereby are special, unique and of extraordinary character and that, if any Party violates or fails or refuses to perform any covenant or agreement made by it herein, the non-breaching Party may be without an adequate remedy at law. If any Party violates or fails or refuses to perform any covenant or agreement made by such Party herein, the non-breaching Party or Parties may, subject to the terms hereof and in addition to any remedy at law for damages or other relief, institute and prosecute an action in any court of competent jurisdiction to enforce specific performance of such covenant or agreement or seek any other equitable relief.

Section 8.4 Break Up Fee.

(a) If this Agreement is validly terminated by Seller pursuant to Section 8.1(b) or by Buyer pursuant to Section 8.1(g), then in lieu of all other Claims and remedies that might otherwise be available with respect thereto, including elsewhere under this Agreement and notwithstanding any other provision of this Agreement, Buyer hereby agrees to pay immediately to Seller, as liquidated damages in connection with such termination, an amount in immediately available funds equal to (i) $40,000,000 minus (ii) all amounts (if any) paid by or on behalf of Buyer to Seller prior to termination of this Agreement with respect to any Claim brought under or with respect to this Agreement or the transactions contemplated hereby.

(b) The provisions for payment of liquidated damages in this Section 8.4 have been included because, in the event of termination of this Agreement as described in Section 8.4(a), the actual damages to be incurred by Seller are reasonably expected to approximate the amount of liquidated damages set forth in this Section 8.4 and because the actual amount of such damages would be difficult if not impossible to measure precisely. Buyer and Seller further agree that if Buyer is or becomes obligated to pay a fee pursuant to Section 8.4(a), the right to receive such fee shall be the sole and exclusive remedy of Seller against Buyer, its Affiliates and their respective Representatives with respect to any and all matters arising from or relating to the Acquired Assets, this Agreement and/or the transactions contemplated hereby except with respect to fraud.

ARTICLE IX
INDEMNIFICATION, LIMITATIONS OF LIABILITY AND WAIVERS

Section 9.1 Indemnification.

(a) Subject to Section 9.2, from and after the Closing, Seller shall indemnify, defend and hold harmless Buyer, its Affiliates and each of their respective Representatives (collectively, the "***Buyer Indemnified Parties***") from and against all Losses incurred or suffered by any Buyer Indemnified Party resulting from:

(i) any breach of any representation or warranty of Seller contained in this Agreement or in the certificate delivered pursuant to Section 6.3;

(ii) any breach of any covenant or agreement of Seller contained in this Agreement;

(iii) any Excluded Asset and/or the Excluded Liabilities; and

(iv) any Claim or Loss relating to the assets that are the subject of the Solar Facility License Agreement (excluding any Claim or Loss with respect to any failure by Buyer to perform under the Solar Facility License Agreement).

(b) Subject to Section 9.2, from and after Closing, Buyer shall, except, in each case for, and solely to the extent of, Losses that are otherwise subject to indemnification by Seller pursuant to Section 9.1(a), indemnify, defend and hold Seller, its Affiliates and each of their respective Representatives (collectively, the "***Seller Indemnified Parties***") harmless from and against all Losses incurred or suffered by any Seller Indemnified Party resulting from:

(i) any breach of any representation or warranty of Buyer contained in this Agreement or in the certificate delivered pursuant to Section 7.3;

(ii) any breach of any covenant or agreement of Buyer contained in this Agreement;

(iii) the Assumed Liabilities;

(iv) any Taxes that are the responsibility of Buyer pursuant to Section 2.10 or Section 5.11 of this Agreement, or that are attributable to taxable periods beginning after the Closing Date; and

(v) any Claim or Loss relating to, or any draw upon, any Outstanding Coal Support Obligation.

Section 9.2 Limitations of Liability. Notwithstanding anything in this Agreement to the contrary:

(a) the representations and warranties of Seller set forth in Article III (other than (i) the Designated Representations, which shall survive the Closing indefinitely, (ii) the representations and warranties set forth in Section 3.11 (Taxes), which shall survive the Closing until sixty (60) days following the expiration of the applicable statute of limitations, (iii) the representations and warranties set forth in Section 3.15 (Environmental Matters), which shall survive the Closing for a period of four (4) years, and (iv) the representations and warranties of Buyer set forth in Article IV (other than the Designated Representations, which shall survive the Closing indefinitely)) shall survive the Closing for a period of eighteen (18) months. The covenants of the Parties contained in this Agreement that are to be performed prior to the Closing shall survive the Closing for a period of twelve (12) months, and the covenants of the Parties contained in this Agreement that are to be performed subsequent to the Closing shall terminate at the expiration of the applicable statute of limitations;

(b) Seller shall have no Liability for a breach of any representation or warranty contained in this Agreement until the aggregate amount of all Losses incurred by the Buyer Indemnified Parties (excluding all Losses arising out of or relating to Liabilities described in clause (ii) of this Section 9.2(b)) equals or exceeds the Deductible Amount, in which event Seller shall be liable for Losses only to the extent they are in excess of the Deductible Amount; provided that (i) the Deductible Amount shall not apply to any Losses relating to an Excluded Liability, a breach of a representation or warranty set forth in Section 3.11 (Taxes) or any Designated Representation, and (ii) in no event shall Seller have any Liability for any breach of a representation or warranty in this Agreement (other than those relating to an Excluded Liability, Taxes or any breach of any Designated Representation) in connection with any single item or group of related items that results in Losses, in any such case, of less than $175,000;

(c) in no event shall Seller’s aggregate Liability arising out of or relating to any breach of any representation or warranty of Seller in this Agreement (other than any representation or warranty set forth in Section 3.11 (Taxes), which shall not be subject to a cap), whether based on contract, tort, strict liability, other Laws or otherwise, exceed (i) 20% of the Base Purchase Price with respect to a breach of any representation or warranty except as set forth in subclause (ii) of this Section 9.2(c), or (ii) exceed 100% of the Base Purchase Price with respect to a breach of any Designated Representation;

(d) any Indemnified Party that becomes aware of a Loss for which it seeks indemnification under this Article IX shall be required to use commercially reasonable efforts to mitigate the Loss;

(e) references to “Material Adverse Effect” or other materiality qualifications (or correlative terms) shall, except with respect to Section 3.21, be disregarded for all purposes of the provisions of Section 9.1;

(f) the Losses suffered by any Indemnified Party shall be calculated after giving effect to any amounts actually received by such Indemnified Party at or prior to the time of calculation in respect thereof, including insurance proceeds (net of the reasonable third party out of pocket costs and expenses associated with such recoveries and any associated increases in insurance premiums) and any associated tax benefits to Buyer (it being understood and agreed that the Indemnified Party shall use its commercially reasonable efforts to seek insurance recoveries in respect of Losses to be indemnified hereunder). If any insurance proceeds or other recoveries from third parties are actually realized (net of the reasonable third party out of pocket costs and expenses associated with such recoveries and any associated increases in insurance premiums) by an Indemnified Party subsequent to the receipt by such Indemnified Party of an indemnification payment hereunder in respect of the claims to which such insurance proceedings or third party recoveries relate, the Indemnified Party shall promptly notify the Indemnifying Party of such receipt and appropriate refunds shall be made promptly to the Indemnifying Party regarding the amount of such indemnification payment;

(g) Losses to any Indemnified Party hereunder shall be determined net of (i) any Tax benefit actually realized by the time of such determination, and (ii) the net present value of Tax benefits reasonably expected to be derived by the Party being indemnified as a result of sustaining such Losses;

(h) unless otherwise required by applicable Law, any indemnity payment made pursuant to this Agreement will be treated as an adjustment to the Purchase Price for all Tax purposes;

(i) in valuing any Loss, no adjustment shall be made as a result of any multiple, increase factor, or any other premium over fair market value, book or historical value which may have been paid by Buyer for the Acquired Assets whether or not such multiple, increase factor or other premium had been used by Buyer at the time of, or in connection with, calculating or preparing its bid, its proposed purchase price for the Acquired Assets or its final purchase price for the Acquired Assets;

(j) any Indemnified Party that becomes aware of a Loss for which it seeks indemnification under this Article IX shall promptly (and, in any event, within thirty (30) days of becoming aware of such Loss) notify the Indemnifying Party in writing of the basis for such Loss, setting forth the nature of such Loss in reasonable detail; the failure of an Indemnified Party to so notify the Indemnifying Party shall not relieve the Indemnifying Party of liability hereunder except to the extent that the cost of providing indemnification for such Loss is actually prejudiced by the failure to give such notice; provided, however, that no Indemnifying Party shall have any obligation to indemnify an Indemnified Party with respect to a Loss unless, prior to the expiration of the applicable survival period set forth in Section 9.2(a), the Indemnified Party shall have notified the Indemnifying Party in writing of the basis for such Loss, setting forth the nature of such Loss in reasonable detail;

(k) notwithstanding anything to the contrary herein, the limitation, covenants, agreements and obligations set forth in Section 9.2 shall not apply to Seller's indemnification obligations pursuant to Section 9.1(a)(iii), or any representation or warranty set forth in Section 3.11(Taxes) and any breach of any covenant, agreement or obligation in this Agreement.;

(l) from and after Closing, Seller shall have no right of contribution from any of the Acquired Assets with respect to any breach of a representation, warranty, covenant or agreement of Seller in this Agreement or any Ancillary Agreement;

(m) For Tax purposes, any indemnity payments made pursuant to this Article IX shall be treated as an adjustment to the purchase price of the Acquired Assets and Acquired Entity; and

(n) Seller shall have no liability for any Claim against Buyer or its Affiliates with respect to any breach of the representations set forth in Sections 3.15(a) and (d) and any Excluded Liability set forth in Sections 2.4(f), (g) and (h) if and to the extent any such Claim arose as the result of a notification made by Buyer or its Affiliates to any Person, including any Governmental Authority; provided that the limitation on Seller's liability set forth in this Section 9.2(n) shall not apply where (i) such notification was (A) required by Law, (B) reasonably required to avoid or mitigate an imminent and substantial endangerment to human health or the environment, or (C) consistent with Good Utility Practice; and (ii) Buyer provides, or causes to be provided, to Seller advance notice of such notification. To the extent permitted by, and subject in all respects to, the provisions of Section 9.4, if, as the result of any such notification, Buyer becomes subject to a Claim and Buyer believes it has a claim for indemnification against Seller under Section 9.1(a) as a result, then (1) Buyer shall promptly notify Seller in writing of the basis for such claim setting forth the nature of the Claim in reasonable detail, and (2) Seller shall be entitled to participate in the Claim and, to the extent that it wishes, to assume the defense of such Claim.

Section 9.3 Waiver of Remedies.

(a) From and after Closing, the rights and remedies of the Parties under this Article IX are, except in the case of fraud, exclusive and in lieu of any and all other rights and remedies which the Parties may have under this Agreement or otherwise, including with respect to: (i) any breach of any representation or warranty set forth in this Agreement, (ii) any breach or failure to perform any covenant or agreement set forth in this Agreement or (iii) the Assumed Liabilities or the Excluded Liabilities, as the case may be. Without limiting the foregoing, with respect to the Acquired Assets, Buyer, for itself and its Affiliates, does, effective as of Closing, hereby irrevocably release, hold harmless and forever discharge Seller and its Affiliates from any and all Environmental Claims (other than those Environmental Claims for which Seller is obligated to indemnify Buyer pursuant to this Article IX) related to or arising from the Acquired Assets. In furtherance of the foregoing, Buyer, for itself and on behalf of its Representatives, hereby, effective as of Closing, irrevocably waives any and all rights and benefits with respect to such Environmental Claims (other than those Environmental Claims for which Seller is obligated to indemnify Buyer pursuant to this Article IX) that it now has, or in the future may have conferred upon it by virtue of any Law or common law principle, which provides that a general release does not extend to claims which a party does not know or suspect to exist in its favor at the time of executing the release, if knowledge of such claims would have materially affected such party's settlement with the obligor. In this connection, Buyer hereby acknowledges that it is aware that factual matters now unknown to it may have given, or hereafter may give, rise to Environmental Claims that have not been made prior to the date of this Agreement, and will not be made prior to the Closing Date, and Buyer further agrees that this release set forth in this Section 9.3(a) has been negotiated and agreed upon in light of that awareness, and Buyer, for itself and on behalf of its Representatives, nevertheless hereby intends irrevocably to release, hold harmless and forever discharge Seller and its Affiliates from all such Environmental Claims (other than those Environmental Claims for which Seller is obligated to indemnify Buyer pursuant to this Article IX).

(b) NOTWITHSTANDING ANYTHING IN THIS AGREEMENT TO THE CONTRARY, NO PARTY SHALL BE LIABLE FOR SPECIAL, PUNITIVE, EXEMPLARY,

INCIDENTAL, CONSEQUENTIAL OR INDIRECT DAMAGES OR LOST PROFITS (EXCEPT FOR AS EXPRESSLY PROVIDED IN SECTIONS 5.13 AND 5.14 AND EXCEPT FOR ANY LOST PROFITS THAT ARE DIRECT DAMAGES) WHETHER BASED ON CONTRACT, TORT, STRICT LIABILITY, OTHER LAW OR OTHERWISE AND WHETHER OR NOT ARISING FROM THE OTHER PARTY’S SOLE, JOINT OR CONCURRENT NEGLIGENCE, STRICT LIABILITY OR OTHER FAULT (“***NON-REIMBURSABLE DAMAGES***”), PROVIDED, THAT ANY AMOUNTS PAYABLE TO THIRD PARTIES PURSUANT TO A THIRD-PARTY CLAIM SHALL NOT BE DEEMED NON-REIMBURSABLE DAMAGES.

Section 9.4 Procedure with Respect to Third-Party Claims.

(a) If any Party becomes subject to a pending or threatened Claim of a third party and such Party (the “***Claiming Party***”) believes it has a claim against the other Party (the “***Responding Party***”) as a result, then the Claiming Party shall promptly notify the Responding Party in writing of the basis for such Claim setting forth the nature of the Claim in reasonable detail. The failure of the Claiming Party to so notify the Responding Party shall not relieve the Responding Party of liability hereunder except to the extent that the defense of such Claim is actually prejudiced by the failure to give such notice.

(b) If any proceeding is brought by a third party against a Claiming Party and the Claiming Party gives notice to the Responding Party pursuant to this Section 9.4, the Responding Party shall be entitled to participate in such proceeding and, to the extent that it wishes, to assume the defense of such proceeding, if (i) the Responding Party provides written notice to the Claiming Party that the Responding Party intends to undertake such defense, (ii) the Responding Party conducts the defense of the third-party Claim actively and diligently with counsel reasonably satisfactory to the Claiming Party, and (iii) if the Responding Party is a party to the proceeding, the Responding Party or the Claiming Party has not reasonably determined in good faith that joint representation would be inappropriate because of a conflict of interest. The Claiming Party, in its sole discretion, shall have the right to employ separate counsel in any such action and to participate in the defense thereof, and, except where there is a conflict of interest that makes it inappropriate for the same counsel to represent both the Claiming Party and the Responding Party, the fees and expenses of such counsel shall be paid by such Claiming Party. The Claiming Party and the Responding Party shall fully cooperate with each other and their respective counsel in the defense or compromise of such Claim. No compromise or settlement of such Claims may be effected by the Responding Party without the Claiming Party’s consent unless (x) there is no finding or admission of any violation of Law or any violation of the rights of any Person and no adverse effect on any other Claims that may be made against the Claiming Party, (y) the sole relief provided is monetary damages that are paid in full by the Responding Party, and (z) the third party who brought the Claim against the Claiming Party executes a full release of such Claim with respect to the Claiming Party and its Affiliates.

(c) If (i) notice is given to the Responding Party of the commencement of any third-party legal proceeding and the Responding Party does not, within thirty (30) days after the Claiming Party’s notice is given, give written notice to the Claiming Party of its election to assume the defense of such legal proceeding, (ii) the conditions set forth in clause (ii) of Section 9.4(b) above become unsatisfied, or (iii) the Claiming Party determines in good faith that there is a reasonable probability that a legal proceeding may adversely affect it other than as a result of monetary damages for which it would be entitled to indemnification from the Responding Party under this Agreement, then the Claiming Party shall (upon written notice to the Responding Party) have the right to undertake the defense, compromise or settlement of such claim; provided, however, that the Responding Party shall remain otherwise responsible for any liability with respect to amounts arising from or related to such third-party claim, including fees and expenses of counsel, to the extent it is ultimately determined that such Responding Party is liable with respect to such third-party claim under this Agreement. The Responding Party may elect to participate in such legal proceedings, negotiations or defense at any time at its own expense.

ARTICLE X
MISCELLANEOUS

Section 10.1 Notices.

(a) Unless this Agreement specifically requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be deemed properly served, given or made if delivered in person or sent by facsimile, or sent by registered or certified mail, postage prepaid, or by a nationally recognized overnight courier service that provides a receipt of delivery, in each case, to the Parties, or with respect to Article XI, the Guarantor, at the addresses specified below:

If to Buyer, to:

Raven Power Holdings LLC
c/o Riverstone Investment Group
712 Fifth Avenue, 51st Floor
New York, NY 10019
Attention: General Counsel
Facsimile No.: (888) 801-9301

With a copy to:

Topaz Power Management, LP
2705 Bee Caves Road, Suite 340
Austin, TX 78746
Attention: General Counsel
Facsimile No.: (512) 314-8699

If to Seller or Guarantor, to:

Exelon Corporation
10 S. Dearborn, 49th Floor
Chicago, IL 60603
Attention: Carter Culver, Vice President and Deputy General Counsel
Facsimile No.: (312) 294-2754

With a copy to:

Morgan, Lewis & Bockius LLP
1701 Market Street
Philadelphia, PA 19103
Attention: Barbara J. Shander
Facsimile No.: (215) 963-5001

(b) Notice given by personal delivery, mail or overnight courier pursuant to this Section 10.1 shall be effective upon physical receipt. Notice given by facsimile pursuant to this Section 10.1 shall be effective as of the date of confirmed delivery if delivered before 5:00 p.m. Eastern Time on any Business Day or the next succeeding Business Day if confirmed delivery is after 5:00 p.m. Eastern Time on any Business Day or during any non-Business Day. Each Party and the Guarantor may change the address by which proper notice shall be given pursuant to this Section 10.1 by providing notice to the other Party in accordance with this Section.

Section 10.2 Entire Agreement. This Agreement (including the Exhibits and Schedules hereto), together with the Ancillary Agreements and, prior to Closing the Confidentiality Agreement constitute the entire agreement between the Parties and/or the Guarantor and supersede any prior understandings, agreements, or representations by or between the Parties and/or the Guarantor, written or oral, with respect to the subject matter hereof.

Section 10.3 Expenses. Except as otherwise expressly provided in this Agreement, whether or not the transactions contemplated hereby are consummated, each Party and the Guarantor will pay its own costs and expenses incurred in anticipation of, relating to and in connection with the negotiation and execution of this Agreement and the transactions contemplated hereby, including all expenses and costs incurred to obtain approvals required by such Party from Governmental Authorities.

Section 10.4 Disclosure. Seller may, at its option, include in the Schedules items that are not material in order to avoid any misunderstanding, and any such inclusion, or any references to dollar amounts, shall not be deemed to be an acknowledgment or representation that such items are material, to establish any standard of materiality or to define further the meaning of such terms for purposes of this Agreement. Information disclosed in any Schedule shall constitute a disclosure for purposes of all other Schedules notwithstanding the lack of specific cross-reference thereto, but only to the extent the applicability of such disclosure to such other Schedule is reasonably apparent on its face. In no event shall the inclusion of any matter in the Schedules be deemed or interpreted to broaden Seller's representations, warranties, covenants or agreements contained in this Agreement. The mere inclusion of an item in the Schedules shall not be deemed an admission by Seller that such item represents a material exception or fact, event, or circumstance or that such item is reasonably likely to result in a

Material Adverse Effect. The Parties shall promptly notify each other upon becoming aware of (a) the occurrence, or failure to occur, of any event, which occurrence or failure has caused any representation or warranty of such Party contained in this Agreement or in any exhibit, schedule, certificate, document or written instrument attached hereto to be untrue or inaccurate, (b) any failure of such Party to comply with, perform or satisfy, in any respect, any covenant, condition or agreement to be complied with, performed by or satisfied by it under this Agreement or any exhibit, schedule, certificate, document or written instrument attached hereto and (c) except as otherwise provided in this Agreement, any notice or other communication from any Governmental Authority in connection with this Agreement or the transactions contemplated herein; provided, that such disclosure shall not be deemed to cure, or to relieve any Party of any liability or obligation with respect to, any breach of or failure to satisfy any representation, warranty, covenant or agreement or any condition hereunder, and shall not affect any Party's right with respect to indemnification hereunder.

Section 10.5 Waiver. Any term or condition of this Agreement may be waived at any time by the Party that is entitled to the benefit thereof, but no such waiver shall be effective unless set forth in a written instrument duly executed by or on behalf of the Party waiving such term or condition. No waiver by any Party of any term or condition of this Agreement, in any one or more instances, shall be deemed to be or construed as a waiver of the same or any other term or condition of this Agreement on any future occasion. All remedies, either under this Agreement or by Law or otherwise afforded, will be cumulative and not alternative.

Section 10.6 Amendment. This Agreement may be amended, supplemented or modified only by a written instrument duly executed by or on behalf of each Party (and, solely with respect to amendments, supplements or modifications to Article XI, also by the Guarantor).

Section 10.7 No Third Party Beneficiary. Except for the provisions of Section 5.3(c) (which are intended for the benefit of the Persons identified therein), the terms and provisions of this Agreement are intended solely for the benefit of the Parties and their respective successors or permitted assigns, and it is not the intention of the Parties to confer third-party beneficiary rights upon any other Person, including any employee, any beneficiary or dependents thereof, or any collective bargaining representative thereof.

Section 10.8 Assignment; Binding Effect. Buyer shall have the right to assign to any one or more of its Affiliates any of its rights or obligations under this Agreement, any Ancillary Agreement or any other document or instrument, in whole or in part (including the right to acquire any of the Acquired Assets); provided, however, that no assignment hereunder shall relieve Buyer of its obligations under this Agreement and Buyer shall cause such assignees to perform such obligations on behalf of Buyer in accordance with the terms of this Agreement. Buyer may assign its rights to indemnification under this Agreement to Buyer's lenders for collateral security purposes, but such assignment shall not release Buyer from its obligations hereunder. Except as provided in the preceding sentences, neither this Agreement nor any right, interest or obligation hereunder may be assigned by any Party without the prior written consent of the other Party or by the Guarantor without the prior written consent of the Buyer, and in each case any attempt to do so will be void, except for assignments and transfers by operation of Law. Subject to this Section 10.8, this Agreement is binding upon, inures to the benefit of and is enforceable by the Parties and their respective successors and permitted assigns.

Section 10.9 Headings. The headings used in this Agreement have been inserted for convenience of reference only and do not define or limit the provisions hereof.

Section 10.10 Invalid Provisions. If any provision of this Agreement is held to be illegal, invalid or unenforceable under any present or future Law, and if the rights or obligations of any Party or the Guarantor under this Agreement will not be materially and adversely affected thereby, such provision will be fully severable, this Agreement will be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part hereof, the remaining provisions of this Agreement will remain in full force and effect and will not be affected by the illegal, invalid or unenforceable provision or by its severance herefrom and in lieu of such illegal, invalid or unenforceable provision, there will be added automatically as a part of this Agreement a legal, valid and enforceable provision as similar in terms to such illegal, invalid or unenforceable provision as may be possible.

Section 10.11 Counterparts; Facsimile. This Agreement and any signed agreement or instrument entered into in connection with this Agreement, and any amendments hereto or thereto, may be executed in one or more counterparts, all of which shall constitute one and the same instrument. Any such counterpart, to the extent delivered by means of a facsimile machine or by .pdf, .tif, .gif, .peg or similar attachment to electronic mail shall be treated in all manner and respects as an original executed counterpart and shall be considered to have the same binding legal effect as if it were the original signed version thereof delivered in person.

Section 10.12 Bulk Sales. Each Party hereby waives compliance by the other Party with the provision of any bulk sales or transfer laws of any jurisdiction in connection with the transactions contemplated by this Agreement.

Section 10.13 Governing Law; Venue; and Jurisdiction.

(a) This Agreement shall be governed by and construed in accordance with the Laws of the State of New York, without giving effect to any conflict or choice of law provision that would result in the imposition of another state's Law, provided that any dispute relating to real property shall be governed by, and construed in accordance with, the laws of the State of Maryland.

(b) THE PARTIES AND THE GUARANTOR HEREBY IRREVOCABLY SUBMIT TO THE NON-EXCLUSIVE JURISDICTION OF ANY STATE OR FEDERAL COURT IN NEW YORK, NEW YORK IN CONNECTION WITH ANY ACTION, SUIT OR PROCEEDING BROUGHT IN CONNECTION WITH THIS AGREEMENT (INCLUDING ARTICLE XI), AND EACH PARTY AND THE GUARANTOR HEREBY CONSENTS TO THE JURISDICTION OF SUCH COURTS (AND OF THE APPROPRIATE APPELLATE COURTS THEREFROM) IN ANY SUCH SUIT, ACTION OR PROCEEDING AND IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY LAW, ANY OBJECTION THAT IT MAY NOW OR HEREAFTER HAVE TO THE LAYING OF THE VENUE OF ANY SUCH SUIT, ACTION OR PROCEEDING IN ANY SUCH COURT OR THAT ANY SUCH SUIT, ACTION OR PROCEEDING THAT IS BROUGHT IN ANY SUCH COURT HAS BEEN BROUGHT IN AN INCONVENIENT FORUM. DURING THE PERIOD A LEGAL DISPUTE THAT IS FILED IN ACCORDANCE WITH THIS SECTION 10.13 IS

PENDING BEFORE A COURT, ALL ACTIONS, SUITS OR PROCEEDINGS WITH RESPECT TO SUCH LEGAL DISPUTE OR ANY OTHER LEGAL DISPUTE BETWEEN THE PARTIES AND RELATING TO THE TRANSACTIONS CONTEMPLATED HEREBY, INCLUDING ANY COUNTERCLAIM, CROSS-CLAIM OR INTERPLEADER, SHALL BE SUBJECT TO THE EXCLUSIVE JURISDICTION OF SUCH COURT. EACH PARTY AND THE GUARANTOR HEREBY WAIVES, AND SHALL NOT ASSERT AS A DEFENSE IN ANY LEGAL DISPUTE BROUGHT IN CONNECTION WITH THIS AGREEMENT, THAT (A) SUCH ACTION, SUIT OR PROCEEDING MAY NOT BE BROUGHT IN SUCH COURT, (B) SUCH ACTION, SUIT OR PROCEEDING IS BROUGHT IN AN INCONVENIENT FORUM OR (C) THE VENUE OF SUCH ACTION, SUIT OR PROCEEDING IS IMPROPER. EACH PARTY AGREES TO ACCEPT SERVICE OF PROCESS OUT OF ANY OF THE ABOVEMENTIONED COURTS IN ANY SUCH ACTION, SUIT OR PROCEEDING BY REGISTERED OR CERTIFIED MAIL ADDRESSED TO SUCH PARTY AT THE ADDRESS SET FORTH IN SECTION 10.1. A FINAL JUDGMENT IN ANY ACTION, SUIT OR PROCEEDING DESCRIBED IN THIS SECTION 10.13 FOLLOWING THE EXPIRATION OF ANY PERIOD PERMITTED FOR APPEAL AND SUBJECT TO ANY STAY DURING APPEAL SHALL BE CONCLUSIVE AND MAY BE ENFORCED IN OTHER JURISDICTIONS BY SUIT ON THE JUDGMENT OR IN ANY OTHER MANNER PROVIDED BY APPLICABLE LAWS.

(c) EACH PARTY AND THE GUARANTOR HEREBY WAIVES, TO THE FULLEST EXTENT PERMITTED BY LAW, ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY.

Section 10.14 Attorneys’ Fees. If either Party shall bring an action to enforce the provisions of this Agreement, the prevailing Party shall be entitled to recover its reasonable attorneys’ fees and expenses incurred in such action from the non-prevailing Party.

ARTICLE XI GUARANTY

Section 11.1 Guaranty. The Guarantor hereby absolutely and unconditionally guarantees to Buyer the timely payment and performance of the obligations of Seller under this Agreement (“***Guaranteed Obligations***”), provided that, notwithstanding anything contained in this Article XI or otherwise, in no event (a) shall Guarantor’s aggregate Liability in respect of any breach by Seller of the covenant set forth in Section 5.26 exceed $40,000,000, nor shall Guarantor have any Liability in respect of the any breach by Seller of the covenant set forth in Section 5.26 after December 31, 2015, and (b) shall Guarantor’s aggregate Liability in respect of all other Guaranteed Obligations exceed twenty percent (20%) of the Base Purchase Price, nor shall Guarantor have any Liability in respect of such other Guaranteed Obligations after the eighteen (18) month anniversary of the Closing Date (December 31, 2015 or the eighteen (18) month anniversary of the Closing Date, as applicable, the “***Guaranty Expiration Date***”); provided that notwithstanding the foregoing, if any claim has been made by Buyer under this Article XI on or before the applicable Guaranty Expiration Date and such claim has not been fully and finally resolved, then the provisions of this Article XI shall survive with respect to such claim until the date that such claim is finally resolved.

Section 11.2 Effect of Amendments. The Guarantor agrees that Seller may modify, amend and supplement this Agreement and/or any Ancillary Agreement and may delay or extend the Closing Date or the date on which any payment must be made pursuant to such Agreement or delay or extend the date on which any act must be performed by Seller or any other Person, as applicable, thereunder, all without notice to or further assent by the Guarantor, who shall remain bound by the provisions of this Article XI, notwithstanding any such act.

Section 11.3 Waiver of Rights. The Guarantor hereby waives all suretyship defenses and all defenses with respect to the Guaranteed Obligations of promptness, diligence, presentment, demand for payment or performance, protest, notice of dishonor, notice of default, notice of acceptance, and all other notices, demands or conditions whatsoever. Except to the extent set forth in Section 11.1, the obligations of Guarantor under this Agreement are a continuing, absolute, irrevocable and unconditional guaranty by the Guarantor of the Guaranteed Obligations. The Guarantor's obligations hereunder shall remain in full force and effect, shall not be affected, impaired, reduced or modified, and the Guarantor shall have no right to terminate its obligations under this Agreement or to be released, relieved or discharged, in whole or in part, from its payment and performance obligations by reason of the following, all of which the Guarantor hereby waives: (a) any bankruptcy, reorganization, or insolvency under any Law applicable to Seller or any other Person (other than Guarantor), or by any action of a trustee in any such proceeding; (b) any amendment, supplement, modification, waiver, adjustment, compromise, or release of, or any failure to exercise any right, remedy, power or privilege under or in respect of, the Guaranteed Obligations or this Agreement; (c) any merger or consolidation of Seller, Buyer or the Guarantor into or with any other Person or any change in form of organization, name, membership or ownership of Seller, Buyer or Guarantor; (d) any lack of genuineness, validity, legality, enforceability or value of the Guaranteed Obligations or this Agreement; (e) the permitted assignment or transfer of all or any part of this Agreement; and (f) to the extent permitted by Law, any other event, circumstance, act or omission whatsoever which might constitute a legal or equitable discharge of a surety or guarantor.

Section 11.4 Settlements Conditional. Notwithstanding anything to the contrary in this Agreement, including Article XI, if any monies paid by or on behalf of Seller under this Article XI in reduction of the obligations of Seller under this Agreement have to be repaid or rescinded or must otherwise be restored by virtue of any provision or enactment relating to bankruptcy, insolvency, liquidation or otherwise for the time being in force, the liability of the Guarantor under this Article XI shall be computed as if such monies had never been paid by or on behalf of Seller.

Section 11.5 Primary Liability of Guarantor. The Guarantor agrees that Buyer may enforce the guaranty in this Article XI without the necessity at any time of resorting to or exhausting any other security or collateral of any Person. The guaranty set forth in this Article XI is a continuing guaranty of payment and performance and not merely of collection.

[signature pages follow]

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized officer of each Party as of the date first above written.

SELLER:

CONSTELLATION POWER SOURCE GENERATION, INC.

By: ____________________
Name: ____________________
Title: ____________________

BUYER:

RAVEN POWER HOLDINGS LLC

By: ____________________
Name: ____________________
Title: ____________________

Solely with respect to Sections 1.2, 10.1, 10.2, 10.3, 10.6, 10.8, 10.10, 10.13 and Article XI:

EXELON GENERATION COMPANY, LLC

By: ____________________
Name: ____________________
Title: ____________________

Exhibit 31-1

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Christopher M. Crane, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. 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: November 7, 2012

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: November 7, 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 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: November 7, 2012

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: November 7, 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: November 7, 2012

Exhibit 31-6

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: November 7, 2012

Exhibit 31-7

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Craig L. Adams, certify that:

1. I have reviewed this quarterly report on Form 10-Q of PECO Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ CRAIG L. ADAMS

President and Chief Executive Officer
(Principal Executive Officer)

Date: November 7, 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: November 7, 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: November 7, 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: November 7, 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 September 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: November 7, 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 Exelon Corporation for the quarterly period ended September 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: November 7, 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 September 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: November 7, 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 September 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: November 7, 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 September 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: November 7, 2012

Exhibit 32-6

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended September 30, 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: November 7, 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 September 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: November 7, 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 September 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: November 7, 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 September 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: November 7, 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 September 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: November 7, 2012