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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, 2011

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

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			☑	

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, 2011 was:

Exelon Corporation Common Stock, without par value	663,012,607
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,519
PECO Energy Company Common Stock, without par value	170,478,507

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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
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon's holding company
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Enterprises	Exelon Enterprises Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
PETT	PECO Energy Transition Trust
Registrants	Exelon, Generation, ComEd, and PECO, collectively

Other Terms and Abbreviations	
Note "__" of the 2010 Form 10-K	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2010 Annual Report on Form 10-K
1998 restructuring settlement	PECO's 1998 settlement of its restructuring case mandated by the Competition Act
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 Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004
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	American Recovery and Reinvestment Act of 2009
ASLB	Atomic Safety Licensing Board
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
CFL	Compact Fluorescent Light
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
CPI	Consumer Price Index
CTC	Competitive Transition Charge
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP Program	Default Service Provider Program
EE&C	Energy Efficiency and Conservation/Demand
EGS	Electric Generation Supplier
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act, as amended
EROA	Expected Rate of Return on Assets

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Other Terms and Abbreviations

ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas
GRT	Gross Receipts Tax
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
HAP	Hazardous air pollutants
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
IFRS	International Financial Reporting Standards
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
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
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-Regulated Agreements Units	Former AmerGen nuclear generating units and portions of the Peach Bottom nuclear generating units whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NWPA	Nuclear Waste Policy Act of 1982

GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Other Terms and Abbreviations

NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
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
Prescription Drug Act	Medicare Prescription Drug Improvement and Modernization Drug Act of 2003
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PUHCA	Public Utility Holding Company Act of 1935
PURTA	Pennsylvania Public Realty Tax Act
RCRA	Federal Resource Conservation and Recovery Act
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Former ComEd and former PECO nuclear generating units whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RES	Retail Electric Suppliers
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
Rider	Reconcilable Surcharge Recovery Mechanism
RMC	Risk Management Committee
RPS	Renewable Energy Portfolio Standards
RPM	PJM Reliability Pricing Model
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
SECA	Seams Elimination Charge/Cost Adjustments/Assignment
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
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
VIE	Variable Interest Entity

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 the Registrants' 2010 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 13 of this Report; and (b) 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

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

(In millions, except per share data)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Operating revenues	$ 5,295	$ 5,291	$14,933	$14,150
Operating expenses				
Purchased power	1,711	1,481	4,602	3,273
Fuel	451	475	1,462	1,469
Operating and maintenance	1,354	1,122	3,725	3,298
Operating and maintenance for regulatory required programs	59	37	138	98
Depreciation and amortization	332	578	987	1,611
Taxes other than income	207	232	602	615
Total operating expenses	4,114	3,925	11,516	10,364
Operating income	1,181	1,366	3,417	3,786
Other income and deductions				
Interest expense	(176)	(169)	(526)	(615)
Interest expense to affiliates, net	(6)	(6)	(19)	(19)
Other, net	(143)	206	51	178
Total other income and deductions	(325)	31	(494)	(456)
Income before income taxes	856	1,397	2,923	3,330
Income taxes	255	552	1,034	1,291
Net income	601	845	1,889	2,039
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic (cost) benefit	(1)	3	(3)	(8)
Actuarial loss reclassified to periodic cost	33	24	100	86
Transition obligation reclassified to periodic cost	1	—	2	5
Pension and non-pension postretirement benefit plans valuation adjustment	—	2	39	(18)
Change in unrealized gain (loss) on cash flow hedges	(64)	222	(255)	196
Other comprehensive income (loss)	(31)	251	(117)	261
Comprehensive income	$ 570	$ 1,096	$ 1,772	$ 2,300
Average shares of common stock outstanding:				
Basic	663	662	663	661
Diluted	665	663	664	662
Earnings per average common share:				
Basic	$ 0.91	$ 1.28	$ 2.85	$ 3.08
Diluted	$ 0.90	$ 1.27	$ 2.84	$ 3.08
Dividends per common share	$ 0.53	$ 0.53	$ 1.58	$ 1.58

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2011	2010
Cash flows from operating activities		
Net income	$ 1,889	$ 2,039
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel amortization	1,702	2,255
Deferred income taxes and amortization of investment tax credits	1,008	240
Net fair value changes related to derivatives	360	(281)
Net realized and unrealized losses (gains) on nuclear decommissioning trust fund investments	90	(49)
Other non-cash operating activities	703	468
Changes in assets and liabilities:		
Accounts receivable	3	(172)
Inventories	(44)	(52)
Accounts payable, accrued expenses and other current liabilities	(400)	(53)
Option premiums received (paid), net	59	(101)
Counterparty collateral received (posted), net	(807)	289
Income taxes	532	310
Pension and non-pension postretirement benefit contributions	(2,089)	(740)
Other assets and liabilities	(89)	(41)
Net cash flows provided by operating activities	2,917	4,112
Cash flows from investing activities		
Capital expenditures	(2,972)	(2,382)
Proceeds from nuclear decommissioning trust fund sales	3,120	2,756
Investment in nuclear decommissioning trust funds	(3,293)	(2,864)
Acquisitions	(380)	—
Change in restricted cash	(532)	427
Other investing activities	26	26
Net cash flows used in investing activities	(4,031)	(2,037)
Cash flows from financing activities		
Changes in short-term debt	462	(90)
Issuance of long-term debt	1,199	1,398
Retirement of long-term debt	(3)	(827)
Retirement of long-term debt of variable interest entity	—	(806)
Dividends paid on common stock	(1,044)	(1,042)
Proceeds from employee stock plans	26	34
Other financing activities	(67)	(17)
Net cash flows provided by (used in) financing activities	573	(1,350)
Decrease (increase) in cash and cash equivalents	(541)	725
Cash and cash equivalents at beginning of period	1,612	2,010
Cash and cash equivalents at end of period	$ 1,071	$ 2,735

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,071	$ 1,612
Restricted cash and investments	565	30
Accounts receivable, net		
Customer ($351 and $346 gross accounts receivable pledged as collateral as of September 30, 2011 and December 31, 2010, respectively)	1,685	1,932
Other	930	1,196
Mark-to-market derivative assets	478	487
Inventories, net		
Fossil fuel	203	216
Materials and supplies	648	590
Deferred income taxes	183	—
Regulatory assets	31	10
Other	493	325
Total current assets	6,287	6,398
Property, plant and equipment, net	31,882	29,941
Deferred debits and other assets		
Regulatory assets	4,381	4,140
Nuclear decommissioning trust funds	6,226	6,408
Investments	740	717
Investments in affiliates	14	15
Goodwill	2,625	2,625
Mark-to-market derivative assets	300	409
Pledged assets for Zion Station decommissioning	763	824
Other	938	763
Total deferred debits and other assets	15,987	15,901
Total assets	$ 54,156	$ 52,240

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2011	December 31, 2010
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 462	$ —
Short-term notes payable — accounts receivable agreement	225	225
Long-term debt due within one year	1,239	599
Accounts payable	1,388	1,373
Accrued expenses	1,053	1,040
Deferred income taxes	—	85
Regulatory liabilities	60	44
Mark-to-market derivative liabilities	52	38
Other	498	836
Total current liabilities	4,977	4,240
Long-term debt	12,175	11,614
Long-term debt to financing trusts	390	390
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	7,958	6,621
Asset retirement obligations	3,808	3,494
Pension obligations	1,475	3,658
Non-pension postretirement benefit obligations	2,371	2,218
Spent nuclear fuel obligation	1,019	1,018
Regulatory liabilities	3,601	3,555
Mark-to-market derivative liabilities	79	21
Payable for Zion Station decommissioning	604	659
Other	1,253	1,102
Total deferred credits and other liabilities	22,168	22,346
Total liabilities	39,710	38,590
Commitments and contingencies		
Preferred securities of subsidiary	87	87
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 663 shares outstanding at September 30, 2011 and 662 shares outstanding at December 31, 2010, respectively)	9,077	9,006
Treasury stock, at cost (35 shares at September 30, 2011 and December 31, 2010, respectively)	(2,327)	(2,327)
Retained earnings	10,146	9,304
Accumulated other comprehensive loss, net	(2,540)	(2,423)
Total shareholders' equity	14,356	13,560
Noncontrolling interest	3	3
Total equity	14,359	13,563
Total liabilities and shareholders' equity	$ 54,156	$ 52,240

See the Combined Notes to Consolidated Financial Statements

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

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interest	Total Equity
Balance, December 31, 2010	696,589	$ 9,006	$(2,327)	$ 9,304	$ (2,423)	$ 3	$13,563
Net income	—	—	—	1,889	—	—	1,889
Long-term incentive plan activity	1,167	71	—	—	—	—	71
Common stock dividends	—	—	—	(1,047)	—	—	(1,047)
Other comprehensive loss net of income taxes of $72	—	—	—	—	(117)	—	(117)
Balance, September 30, 2011	697,756	$ 9,077	$(2,327)	$10,146	$ (2,540)	$ 3	$14,359

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC

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

(In millions)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Operating revenues				
Operating revenues	$ 2,558	$ 1,877	$ 7,291	$ 5,098
Operating revenues from affiliates	304	778	856	2,330
Total operating revenues	2,862	2,655	8,147	7,428
Operating expenses				
Purchased power	680	494	1,801	1,251
Fuel	432	451	1,222	1,191
Operating and maintenance	713	580	2,084	1,865
Operating and maintenance from affiliates	77	69	222	216
Depreciation and amortization	139	121	416	344
Taxes other than income	67	57	199	175
Total operating expenses	2,108	1,772	5,944	5,042
Operating income	754	883	2,203	2,386
Other income and deductions				
Interest expense	(37)	(37)	(128)	(109)
Other, net	(164)	192	(12)	138
Total other income and deductions	(201)	155	(140)	29
Income before income taxes	553	1,038	2,063	2,415
Income taxes	167	433	738	867
Net income	386	605	1,325	1,548
Other comprehensive income (loss), net of income taxes				
Change in unrealized gain (loss) on cash flow hedges	(125)	292	(448)	298
Other comprehensive income (loss)	(125)	292	(448)	298
Comprehensive income	$ 261	$ 897	$ 877	$ 1,846

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, 2011	Nine Months Ended September 30, 2010
Cash flows from operating activities		
Net income	$ 1,325	$ 1,548
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel amortization	1,131	987
Deferred income taxes and amortization of investment tax credits	336	409
Net fair value changes related to derivatives	360	(281)
Net realized and unrealized losses (gains) on nuclear decommissioning trust fund investments	90	(49)
Other non-cash operating activities	362	164
Changes in assets and liabilities:		
Accounts receivable	(165)	(11)
Receivables from and payables to affiliates, net	210	76
Inventories	(32)	(50)
Accounts payable, accrued expenses and other current liabilities	(1)	(162)
Option premiums received (paid), net	59	(101)
Counterparty collateral (paid) received, net	(804)	443
Income taxes	268	(13)
Pension and non-pension postretirement benefit contributions	(952)	(345)
Other assets and liabilities	(65)	(52)
Net cash flows provided by operating activities	2,122	2,563
Cash flows from investing activities		
Capital expenditures	(1,865)	(1,405)
Proceeds from nuclear decommissioning trust fund sales	3,120	2,756
Investment in nuclear decommissioning trust funds	(3,293)	(2,864)
Acquisitions	(380)	—
Change in restricted cash	—	3
Other investing activities	(3)	9
Net cash flows used in investing activities	(2,421)	(1,501)
Cash flows from financing activities		
Changes in short-term debt	72	—
Issuance of long-term debt	—	898
Retirement of long-term debt	(2)	(214)
Distribution to member	(61)	(623)
Contribution from member	30	3
Other financing activities	(53)	(16)
Net cash flows (used in) provided by financing activities	(14)	48
(Decrease) increase in cash and cash equivalents	(313)	1,110
Cash and cash equivalents at beginning of period	456	1,099
Cash and cash equivalents at end of period	$ 143	$ 2,209

See the Combined Notes to Consolidated Financial Statements

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 143	$ 456
Restricted cash and cash equivalents	1	1
Accounts receivable, net		
Customer	592	469
Other	219	161
Mark-to-market derivative assets	478	487
Mark-to-market derivative assets with affiliates	417	455
Receivables from affiliates	95	306
Inventories, net		
Fossil fuel	117	129
Materials and supplies	546	500
Other	171	123
Total current assets	2,779	3,087
Property, plant and equipment, net	13,042	11,662
Deferred debits and other assets		
Nuclear decommissioning trust funds	6,226	6,408
Investments	38	35
Mark-to-market derivative assets	285	391
Mark-to-market derivative assets with affiliates	247	525
Prepaid pension asset	2,097	1,236
Pledged assets for Zion Station decommissioning	763	824
Other	609	366
Total deferred debits and other assets	10,265	9,785
Total assets	$ 26,086	$ 24,534

See the Combined Notes to Consolidated Financial Statements

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2011	December 31, 2010
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 72	$ —
Long-term debt due within one year	3	3
Accounts payable	746	749
Accrued expenses	676	391
Payables to affiliates	47	47
Deferred income taxes	153	427
Mark-to-market derivative liabilities	49	34
Other	161	192
Total current liabilities	1,907	1,843
Long-term debt	3,674	3,676
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,635	3,318
Asset retirement obligations	3,691	3,357
Non-pension postretirement benefit obligations	788	692
Spent nuclear fuel obligation	1,019	1,018
Payables to affiliates	2,078	2,267
Mark-to-market derivative liabilities	31	21
Payable for Zion Station decommissioning	604	659
Other	636	506
Total deferred credits and other liabilities	12,482	11,838
Total liabilities	18,063	17,357
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	3,556	3,526
Undistributed earnings	3,897	2,633
Accumulated other comprehensive income, net	565	1,013
Total member's equity	8,018	7,172
Noncontrolling interest	5	5
Total equity	8,023	7,177
Total liabilities and equity	$ 26,086	$ 24,534

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Member's Equity: Membership Interest	Member's Equity: Undistributed Earnings	Member's Equity: Accumulated Other Comprehensive Income, net	Noncontrolling Interest	Total Equity
Balance, December 31, 2010	$ 3,526	$ 2,633	$ 1,013	$ 5	$7,177
Net income	—	1,325	—	—	1,325
Allocation of tax benefit from member	30	—	—	—	30
Distribution to member	—	(61)	—	—	(61)
Other comprehensive loss, net of income taxes of $293	—	—	(448)	—	(448)
Balance, September 30, 2011	$ 3,556	$ 3,897	$ 565	$ 5	$8,023

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY

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

(In millions)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Operating revenues				
Operating revenues	$ 1,783	$ 1,918	$ 4,692	$ 4,831
Operating revenues from affiliates	1	—	2	1
Total operating revenues	1,784	1,918	4,694	4,832
Operating expenses				
Purchased power	773	910	1,986	1,810
Purchased power from affiliate	159	202	450	826
Operating and maintenance	313	260	733	620
Operating and maintenance from affiliate	40	38	113	113
Operating and maintenance for regulatory required programs	43	22	84	62
Depreciation and amortization	135	126	405	386
Taxes other than income	78	81	226	188
Total operating expenses	1,541	1,639	3,997	4,005
Operating income	243	279	697	827
Other income and deductions				
Interest expense	(82)	(79)	(246)	(290)
Interest expense to affiliates, net	(4)	(3)	(11)	(10)
Other, net	16	3	24	14
Total other income and deductions	(70)	(79)	(233)	(286)
Income before income taxes	173	200	464	541
Income taxes	61	79	169	295
Net income	112	121	295	246
Other comprehensive income, net of income taxes				
Change in unrealized gain on cash flow hedges	—	4	—	—
Other comprehensive income	—	4	—	—
Comprehensive income	$ 112	$ 125	$ 295	$ 246

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2011	2010
Cash flows from operating activities		
Net income	$ 295	$ 246
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	405	387
Deferred income taxes and amortization of investment tax credits	527	199
Other non-cash operating activities	210	162
Changes in assets and liabilities:		
Accounts receivable	(4)	(72)
Receivables from and payables to affiliates, net	(13)	(69)
Inventories	(11)	(2)
Accounts payable, accrued expenses and other current liabilities	(160)	224
Counterparty collateral paid, net	(3)	(154)
Income taxes	211	61
Pension and non-pension postretirement benefit contributions	(871)	(254)
Other assets and liabilities	29	(86)
Net cash flows provided by operating activities	615	642
Cash flows from investing activities		
Capital expenditures	(758)	(686)
Change in restricted cash	(536)	—
Other investing activities	18	16
Net cash flows used in investing activities	(1,276)	(670)
Cash flows from financing activities		
Changes in short-term debt	—	(90)
Issuance of long-term debt	1,199	500
Retirement of long-term debt	(1)	(213)
Contributions from parent	—	2
Dividends paid on common stock	(225)	(225)
Other financing activities	(6)	(3)
Net cash flows provided by (used in) financing activities	967	(29)
Increase (Decrease) in cash and cash equivalents	306	(57)
Cash and cash equivalents at beginning of period	50	91
Cash and cash equivalents at end of period	$ 356	$ 34

See the Combined Notes to Consolidated Financial Statements

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 356	$ 50
Restricted cash	539	—
Accounts receivable, net		
Customer	697	768
Other	372	525
Inventories, net	83	72
Deferred income taxes	84	115
Counterparty collateral deposited	159	153
Regulatory assets	441	456
Other	21	12
Total current assets	2,752	2,151
Property, plant and equipment, net	12,955	12,578
Deferred debits and other assets		
Regulatory assets	733	947
Investments	21	23
Investments in affiliates	6	6
Goodwill	2,625	2,625
Receivables from affiliates	1,751	1,895
Mark-to-market derivative assets	—	4
Prepaid pension asset	1,829	1,039
Other	311	384
Total deferred debits and other assets	7,276	6,923
Total assets	$ 22,983	$ 21,652

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2011	December 31, 2010
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long-term debt due within one year	$ 987	$ 347
Accounts payable	305	332
Accrued expenses	234	366
Payables to affiliates	385	398
Customer deposits	135	130
Regulatory liabilities	17	19
Mark-to-market derivative liability with affiliate	415	450
Other	75	92
Total current liabilities	2,553	2,134
Long-term debt	5,215	4,654
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,852	3,308
Asset retirement obligations	89	105
Non-pension postretirement benefits obligations	350	271
Regulatory liabilities	3,038	3,137
Mark-to-market derivative liability	48	—
Mark-to-market derivative liability with affiliate	247	525
Other	405	402
Total deferred credits and other liabilities	8,029	7,748
Total liabilities	16,003	14,742
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	4,992	4,992
Retained earnings	401	331
Accumulated other comprehensive loss, net	(1)	(1)
Total shareholders' equity	6,980	6,910
Total liabilities and shareholders' equity	$ 22,983	$ 21,652

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, 2010	$ 1,588	$4,992	$ (1,639)	$ 1,970	$ (1)	$ 6,910
Net income	—	—	295	—	—	295
Appropriation of retained earnings for future dividends	—	—	(295)	295	—	—
Common stock dividends	—	—	—	(225)	—	(225)
Balance, September 30, 2011	$ 1,588	$4,992	$ (1,639)	$ 2,040	$ (1)	$ 6,980

See the Combined Notes to Consolidated Financial Statements

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PECO ENERGY COMPANY

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

(In millions)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Operating revenues				
Operating revenues	$ 944	$ 1,494	$ 2,938	$ 4,216
Operating revenues from affiliates	2	1	4	4
Total operating revenues	946	1,495	2,942	4,220
Operating expenses				
Purchased power	308	76	871	211
Purchased power from affiliate	137	574	394	1,498
Fuel	19	23	241	278
Operating and maintenance	179	155	475	440
Operating and maintenance from affiliates	24	21	68	67
Operating and maintenance for regulatory required programs	16	15	54	36
Depreciation and amortization	51	326	150	859
Taxes other than income	59	90	165	240
Total operating expenses	793	1,280	2,418	3,629
Operating income	153	215	524	591
Other income and deductions				
Interest expense	(31)	(35)	(93)	(151)
Interest expense to affiliates, net	(3)	(3)	(9)	(9)
Other, net	3	3	11	6
Total other income and deductions	(31)	(35)	(91)	(154)
Income before income taxes	122	180	433	437
Income taxes	17	53	119	134
Net income	105	127	314	303
Preferred security dividends	1	1	3	3
Net income on common stock	104	126	311	300
Comprehensive income, net of income taxes				
Net income	105	127	314	303
Other comprehensive loss, net of income taxes				
Amortization of realized gain on net settled cash flow swaps	—	—	—	(1)
Other comprehensive loss	—	—	—	(1)
Comprehensive income	$ 105	$ 127	$ 314	$ 302

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2011	2010
Cash flows from operating activities		
Net income	$ 314	$ 303
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	150	859
Deferred income taxes and amortization of investment tax credits	181	(405)
Other non-cash operating activities	74	85
Changes in assets and liabilities:		
Accounts receivable	241	(104)
Receivables from and payables to affiliates, net	(217)	(12)
Inventories	—	2
Accounts payable, accrued expenses and other current liabilities	24	(20)
Income taxes	27	243
Pension and non-pension postretirement benefit contributions	(110)	(68)
Other assets and liabilities	(28)	36
Net cash flows provided by operating activities	656	919
Cash flows from investing activities		
Capital expenditures	(321)	(358)
Changes in Exelon intercompany money pool	(91)	—
Change in restricted cash	(2)	412
Other investing activities	12	7
Net cash flows (used in) provided by investing activities	(402)	61
Cash flows from financing activities		
Retirement of long-term debt of variable interest entity	—	(806)
Contributions from parent	18	1
Dividends paid on common stock	(268)	(178)
Dividends paid on preferred securities	(3)	(3)
Repayment of receivable from parent	—	135
Other financing activities	(5)	—
Net cash flows used in financing activities	(258)	(851)
Increase (decrease) in cash and cash equivalents	(4)	129
Cash and cash equivalents at beginning of period	522	303
Cash and cash equivalents at end of period	$ 518	$ 432

See the Combined Notes to Consolidated Financial Statements

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 518	$ 522
Restricted cash and cash equivalents	2	—
Accounts receivable, net		
Customer ($351 and $346 gross accounts receivable pledged as collateral as of September 30, 2011 and December 31, 2010, respectively)	396	695
Other	277	277
Inventories, net		
Fossil fuel	86	87
Materials and supplies	19	18
Deferred income taxes	45	41
Receivable from Exelon intercompany money pool	91	—
Prepaid utility taxes	40	—
Regulatory assets	7	9
Other	43	21
Total current assets	1,524	1,670
Property, plant and equipment, net	5,796	5,620
Deferred debits and other assets		
Regulatory assets	1,233	968
Investments	20	20
Investments in affiliates	8	8
Receivable from affiliates	329	375
Prepaid pension asset	384	281
Other	42	43
Total deferred debits and other assets	2,016	1,695
Total assets	$ 9,336	$ 8,985

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2011	December 31, 2010
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term notes payable — accounts receivable agreement	$ 225	$ 225
Long-term debt due within one year	250	250
Accounts payable	257	201
Accrued expenses	99	95
Payables to affiliates	58	275
Customer deposits	54	65
Regulatory liabilities	43	25
Mark-to-market derivative liabilities	1	4
Mark-to-market derivative liabilities with affiliate	2	5
Other	21	18
Total current liabilities	1,010	1,163
Long-term debt	1,972	1,972
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,098	1,823
Asset retirement obligations	28	32
Non-pension postretirement benefits obligations	310	292
Regulatory liabilities	563	418
Other	140	131
Total deferred credits and other liabilities	3,139	2,696
Total liabilities	6,305	6,015
Commitments and contingencies		
Preferred securities	87	87
Shareholders' equity		
Common stock	2,379	2,361
Retained earnings	565	522
Total shareholders' equity	2,944	2,883
Total liabilities and shareholders' equity	$ 9,336	$ 8,985

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity
Balance, December 31, 2010	$ 2,361	$ 522	$ 2,883
Net income	—	314	314
Common stock dividends	—	(268)	(268)
Preferred security dividends	—	(3)	(3)
Allocation of tax benefit from parent	18	—	18
Balance, September 30, 2011	$ 2,379	$ 565	$ 2,944

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 and PECO)

Exelon is a utility services holding company engaged, through its principal subsidiaries, in the energy generation and energy delivery businesses. The generation business consists of the electric generating facilities, the wholesale energy marketing operations and competitive retail supply operations of Generation. The energy delivery businesses include the purchase and regulated retail sale of electricity and the provision of distribution and transmission services by ComEd in northern Illinois, including the City of Chicago, and by PECO in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services by PECO in the Pennsylvania counties surrounding the City of Philadelphia.

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology and supply management services. The costs of BSC, including support services, are directly charged or allocated to the applicable subsidiaries using a cost-causative allocation method. Corporate governance type costs that cannot be directly assigned are allocated based on a Modified Massachusetts formula, which is a method that utilizes a combination of gross revenues, total assets, and direct labor costs for the allocation base. The results of Exelon's corporate operations are presented as "Other" within the Combined Notes to the Consolidated Financial Statements and include intercompany eliminations unless otherwise disclosed.

Exelon owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for ComEd, of which Exelon owns more than 99%, and PECO, of which Exelon owns 100% of the common stock but none of PECO's preferred securities. Exelon has reflected the third-party interests in ComEd, which totaled less than $1 million at September 30, 2011, as equity, and PECO's preferred securities as preferred securities of subsidiary in its Consolidated Financial Statements.

Generation owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for Exelon SHC, Inc., of which Generation owns 99% and the remaining 1% is indirectly owned by Exelon, which is eliminated in Exelon's consolidated financial statements; and certain Exelon Wind projects, of which Generation holds majority interests ranging from 94% to 99%, which are presented as Noncontrolling interest on Exelon's and Generation's Consolidated Balance Sheets.

Exelon's Consolidated Financial Statements include the accounts of entities in which Exelon has a controlling financial interest, other than certain financing trusts of ComEd and PECO, and Generation's and PECO's proportionate interests in jointly owned electric utility property, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% or the results of a model that identifies Exelon or one of its subsidiaries as the primary beneficiary of a VIE. Investments and joint ventures, in which Exelon does not have a controlling financial interest and certain financing trusts of ComEd and PECO, are accounted for under the equity or cost method of accounting.

Each of Generation's, ComEd's and PECO'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, 2011 and 2010 and for the three and nine months then ended are unaudited but, in the opinion of the management of each of Exelon, Generation, ComEd and PECO, include all adjustments that are considered necessary for a fair presentation of its respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2010 Consolidated Balance Sheets were taken from audited financial statements. Certain prior year amounts in Exelon's and Generation's Consolidated Statements of Cash Flows and in Exelon's, ComEd's and PECO's Consolidated Balance Sheets have been reclassified between line items for comparative purposes. The reclassifications did not affect the Registrants' net income or cash flows from operating activities. See Note 14 — Supplemental Financial Information for further discussion of the reclassifications to Exelon's and Generation's Consolidated Statements of Cash Flows. 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 Consolidated Financial Statements of Exelon, Generation, ComEd and PECO included in ITEM 8 of their 2010 Form 10-K.

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

During the nine months ended September 30, 2011, the Registrants assessed their involvement with VIE's and determined there were no significant changes in their variable interest, primary beneficiary or consolidation conclusions from December 31, 2010. For further information regarding the Registrants' VIEs, see Note 1 of the 2010 Form 10-K.

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

There were no recently issued accounting standards adopted by the Registrants during the period.

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

Goodwill Impairment Assessments

In September 2011, the FASB issued authoritative guidance amending existing guidance on the annual assessment of goodwill for impairment. Under the revised guidance, entities assessing goodwill for impairment have the option of performing a qualitative assessment before calculating the fair value of the reporting unit (i.e., step one of the two-step fair value based impairment test). If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not less than the carrying amount, the two-step fair value based impairment test would be required. Otherwise, no further testing is required. The guidance is effective for Exelon and ComEd for periods beginning after December 15, 2011 and is not expected to have an impact on their consolidated financial statements.

Statement of Comprehensive Income

In June 2011, the FASB issued authoritative guidance requiring entities to present net income and other comprehensive income in a single continuous statement of comprehensive income or in two separate, but consecutive, statements. The new guidance does not change the components that are recognized in net income and the components that are recognized in other comprehensive income; however, the guidance requires reclassifications between net income and other comprehensive income to be presented at the financial statement line item level. This guidance is effective for the Registrants for periods beginning after December 15, 2011 and is required to be applied retroactively. Each of the Registrants currently presents a single statement of comprehensive income, consistent with the new guidance. The Registrants will present reclassifications at the financial statement line item level in accordance with this guidance upon adoption in 2012.

Fair Value Measurement

In May 2011, the FASB issued authoritative guidance amending existing guidance for measuring fair value and for disclosing information about fair value measurements. The FASB indicated that for many of the requirements, it does not intend for the amendments to result in a change to current accounting. Required disclosures are expanded under the new guidance, especially for fair value measurements that are categorized within Level 3 of the fair value hierarchy, for which quantitative information about the unobservable inputs, the valuation processes used by the entity, and the sensitivity of the measurement to the unobservable inputs will be required. Entities will also be required to disclose the categorization by level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed. The Registrants are currently assessing the effects this guidance may have on their consolidated financial statements. The guidance is effective for the Registrants for periods beginning after December 15, 2011 and is required to be applied prospectively.

3. Regulatory Matters (Exelon, Generation, ComEd and PECO)

Regulatory and Legislative Proceedings (Exelon, Generation, ComEd and PECO)

Except for the matters noted below, the disclosures set forth in Note 2 of the 2010 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

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). On January 25, 2011, ComEd filed a Petition for Leave to Appeal to the Illinois Supreme Court that was denied on March 30, 2011. The ICC has initiated a proceeding on remand. ComEd expects that the ICC will issue a final order in that proceeding in early 2012.

The Court held the ICC abused its discretion in not reducing ComEd's rate base to account for an additional 18 months of accumulated depreciation while including post-test year pro forma plant additions through that period (the same position ComEd took in its 2010 electric distribution rate case (2010 Rate Case) discussed below). The Court's ruling may trigger a refund obligation. An interest charge may accrue on any refund amount. The impact on ComEd's rates and any associated refund obligation should be prospective from no earlier than the date of the Court's ruling on September 30, 2010. ComEd continued to bill rates as established under the ICC's order in the 2007 Rate Case, until June 1, 2011 when the rates set in the 2010 Rate Case became effective. In August 2011, ComEd filed testimony in the remand proceeding that no refunds should be required. If the ICC decides refunds are required, ComEd's testimony stated that the maximum potential refund should be approximately $30 million. Intervenors and ICC Staff have filed testimony in the remand proceeding that ComEd should refund approximately $37 million, including interest, to customers related to post-test year accumulated depreciation.

The Court also reversed the ICC's approval of ComEd's Rider SMP, a program that authorized the installation of 131,000 smart meters in the Chicago area. In 2009, the ICC approved a modified version of Rider SMP (Rider AMP). The Court held that the ICC's approval of Rider SMP constituted illegal single-issue ratemaking. The Court's decision prescribes a new, more stringent, standard for cost recovery riders not specifically authorized by statute. Such riders would be allowed only if: (1) the pass-through cost is imposed by an "external circumstance" and is unexpected, volatile, or fluctuating; and (2) recovery via rider does not change other expenses or increase utility income. Rider AMP is the subject of a separate appeal that is still pending. ComEd does not believe any of its other riders are affected by the Court's ruling.

Subsequent to the Court's ruling, ComEd filed a request with the ICC to allow it to request recovery, through inclusion in the 2010 Rate Case, of operation and maintenance costs that would have been recovered through Rider AMP, as well as continued rider recovery of carrying costs associated with capital investment in the ICC-approved AMI/Customer Applications pilot program until the conclusion of the 2010 rate case. The unrecovered Rider AMP pilot program costs had already been requested in rate base in the 2010 Rate Case. On December 2, 2010, the ICC approved ComEd's request. The investment and the pilot program costs were approved in the 2010 Rate Case proceeding.

ComEd has recognized for accounting purposes its best estimate of any refund obligation, subject to true-up when the ICC issues an order in the remand proceeding.

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

On May 24, 2011, the ICC issued an order in ComEd's 2010 rate case, which became effective on June 1, 2011. The order approved a $143 million increase to ComEd's annual delivery services revenue requirement and a 10.5% rate of return on common equity. As expected, the ICC followed the Court's position on the post-test year accumulated depreciation issue. The order allowed ComEd to establish or reestablish a net amount of approximately $40 million of previously expensed plant balances or new regulatory assets which is reflected as a reduction in operating and maintenance expense and income tax expense for the nine months ended September 30, 2011. The order also affirmed the current regulatory asset for severance costs which was challenged by an intervener in the 2010 Rate Case. The order has been appealed to the Court by several parties, including ComEd. ComEd cannot predict the results of these appeals.

Alternative Regulation Pilot Program (Exelon and ComEd). On August 31, 2010, ComEd filed with the ICC an alternative regulation pilot proposal as a companion proposal to its 2010 Rate Case under a provision of the Illinois Public Utilities Act that contemplates an alternative regulatory structure. Rather than employing the traditional rate setting process in which the utility seeks recovery of costs already incurred, the proposal would have brought utilities, stakeholders, and the ICC together to develop, review and approve ongoing investment programs before those investments are made. The ICC did not approve ComEd's alternative regulation pilot proposal.

Utility Consolidated Billing and Purchase of Receivables (Exelon and ComEd). In November 2008, the Illinois Public Utilities Act was amended to require ComEd to file tariffs establishing Utility Consolidated Billing and Purchase of Receivables services. On December 15, 2010, the ICC approved ComEd's tariff offering PORCB (Purchase of Receivables with Consolidated Billing) services for RES. Beginning in the first quarter of 2011, ComEd is required to buy certain RES receivables, primarily residential and small commercial and industrial customers, at the option of the RES, for electric supply service and then include those amounts on ComEd's bills to customers. Receivables are purchased at a discount to compensate ComEd for uncollectible accounts. ComEd produces consolidated bills for the aforementioned retail customers reflecting charges for electric delivery service and purchased receivables. As of September 30, 2011, the balance of purchased accounts receivable associated with PORCB was $10 million. Under the tariff, ComEd recovers from RES and customers the costs for implementing and operating the program.

Legislation to Modernize Electric Utility Infrastructure and to Update Illinois Ratemaking Process (Exelon and ComEd). ComEd and Ameren are working with State legislators to enact legislation that would modernize Illinois' electric grid. The legislation includes a policy-based approach that would provide a more predictable ratemaking system and would enable utilities to modernize the electric grid and set the stage for fostering economic development while creating and retaining jobs. Many other states are changing or are considering changes to the way they regulate utilities in order to improve the predictability of the ratemaking process.

The Illinois Energy Infrastructure Modernization Act (SB 1652), a prior version of which was originally introduced as HB 14, was passed by the Illinois General Assembly on May 31, 2011. SB 1652 would apply to electric utilities in Illinois on an opt-in basis. SB 1652 provides greater certainty related to the recovery of costs by a utility through a pre-established formula, which would still allow the ICC and interveners the opportunity to review the prudence and reasonableness of costs. If the legislation were to be enacted, upon approval from ComEd's Board of Directors, ComEd would anticipate filing annual electric distribution formula rate cases and investing an additional $2.6 billion (potentially up to $3 billion) in capital expenditures over the next ten years to modernize its system and implement smart grid technology, including improvements to cyber security. These investments would be incremental to ComEd's historical level of capital expenditures. SB 1652 also contains a provision for the IPA to complete a procurement event for energy requirements for the June 2013 through May 2017 period. If SB 1652 is enacted, the procurement event must take place within 120 days of the effective date of the legislation.

On September 12, 2011, the Governor vetoed the bill. The legislation will now go back to the General Assembly, which may elect to override the veto with a super-majority vote during the fourth quarter. If approved in its current form and upon approval of ComEd's Board of Directors, ComEd expects that it would begin to achieve closer to its allowed return on equity, which would have a material positive impact on ComEd's net income as early as 2011. ComEd's commitments in the bill associated with incremental capital expenditures would result in significant cash outflows beginning in 2012. ComEd cannot predict the eventual outcome of SB 1652 resulting from any subsequent actions taken by the Illinois General Assembly. To the extent that the bill is not enacted as currently written or in a comparable form, ComEd will seek alternative methods to achieve reasonable earned returns on equity, which would include additional electric distribution rate case filings with the ICC.

Recovery of Uncollectible Accounts (Exelon and ComEd). On February 2, 2010, the ICC issued an order adopting tariffs for ComEd to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and amounts collected in rates annually. As a result of that ICC order, ComEd recorded a regulatory asset of $70 million and an offsetting reduction in operating and maintenance expense in the first quarter of 2010 for the cumulative under-collections in 2008 and 2009. In addition, ComEd recorded a one-time charge of $10 million to operating and maintenance expense in the first quarter of 2010 for a contribution to the Supplemental Low-Income Energy Assistance Fund which is used to assist low-income residential customers. See Note 2 of the 2010 Form 10-K for additional information.

Illinois Procurement Proceedings (Exelon, Generation and ComEd). ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Since June 2009, under the Illinois Settlement Legislation, the IPA designs, and the ICC approves an electricity supply portfolio for ComEd and the

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

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. On December 21, 2010, the ICC approved the IPA's procurement plan covering the period June 2011 through May 2016. As of September 30, 2011, ComEd has completed the ICC-approved procurement process for its energy requirements through May 2012 as well as a portion of its requirements for each of the years ending in May 2013 and May 2014.

The Illinois Settlement Legislation requires ComEd to purchase an increasing percentage of its electricity requirements from renewable energy resources. On December 17, 2010, ComEd entered into 20-year contracts with several unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. The long term renewables purchased will count towards satisfying ComEd's obligation under the state's RPS and all associated procurement costs will be recoverable from customers. As of September 30, 2011, ComEd has completed the ICC-approved procurement process for RECs through May 2012. See Note 6 — Derivative Financial Instruments for additional information regarding ComEd's financial swap contract with Generation and long-term renewable energy contracts.

On May 25, 2010, the ICC approved a Cash Working Capital (CWC) adjustment to be included in ComEd's energy procurement tariff; however, the ICC did not specify the amount of the allowed recovery, which will ultimately be determined in an annual procurement reconciliation proceeding, based on information from ComEd's most recent rate case. The approved CWC adjustment allows ComEd to recover the time value of money between when it is required to pay for energy and when funds are received from customers. ComEd began billing customers for CWC through its energy procurement rider on June 1, 2010 reflecting the costs included in ComEd's original request to amend the tariff. Because of the uncertainty regarding the amount of CWC recovery, ComEd had been recording a reserve against a portion of these billings. The ICC order in the 2010 Rate Case clarified the method for determining CWC, and as a result, ComEd reversed a $17 million reserve during the second quarter of 2011.

Pennsylvania Regulatory Matters

2010 Pennsylvania Electric and Natural Gas Distribution Rate Cases (Exelon and PECO). On December 16, 2010, the PAPUC approved the settlement of PECO's electric and natural gas distribution rate cases for increases in annual service revenues of $225 million and $20 million, respectively, which became effective on January 1, 2011. The electric settlement provides for recovery of PJM transmission service costs, on a full and current basis through a rider.

In addition, the settlements included a stipulation regarding how tax benefits related to the application of any new IRS guidance on repairs deduction methodology are to be handled from a rate-making perspective. The settlements require that the expected cash benefit from the application of any new guidance to prior tax years be refunded to customers over a seven-year period. On August 19, 2011, the IRS issued Revenue Procedure 2011–43 providing a safe harbor method of tax accounting for electric transmission and distribution property. PECO adopted the safe harbor and elected a method change for the 2010 tax year. The expected total refund to customers for the tax cash benefit from the application of the safe harbor to costs incurred prior to 2010 is $171 million for which PECO has recorded a regulatory liability on Exelon's and PECO's Consolidated Balance Sheets as of September 30, 2011. On October 4, 2011, PECO filed a supplement to its electric distribution tariff to execute the refund to customers of the tax cash benefit related to the IRC Section 481(a) "catch-up" adjustment claimed on the 2010 income tax return, which is subject to adjustment based on the outcome of IRS examinations. Credits will be reflected in customer bills beginning January 1, 2012. Tax benefits claimed prospectively as a result of Revenue Procedure 2011–43 will be reflected as a reduction to income tax expense in the year in which it is claimed on the tax return and will be reflected in the determination of revenue requirements in the next electric distribution base rate cases. See Note 8 — Income Taxes for additional information.

Pennsylvania Procurement Proceedings (Exelon and PECO). PECO's 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 noncurrent regulatory asset and are being recovered through the GSA over its 29-month term. The hourly spot market price full requirements procurement tranches for large commercial and industrial default customers in the September 2010 procurement were not fully subscribed, therefore, PECO served the associated load through spot market purchases and separately procured AECs for the first five months of 2011. In May 2011, PECO entered into contracts with PAPUC-approved bidders for its competitive procurement of electric supply for default electric service commencing June 2011, which included hourly spot market price full requirements contracts to complete the unsubscribed tranches for its large commercial and industrial procurement classes and block energy contracts for the residential procurement class. In September 2011, PECO entered into contracts with PAPUC-approved bidders for its competitive procurement of electric supply for default electric service, which included block contracts for the residential procurement class commencing December 2011 and full requirements fixed price contracts for the residential, small and medium commercial procurement classes commencing June 2012. PECO will conduct three additional competitive procurements over the remainder of the term of its DSP Program.

Electric Purchase of Receivables Program. PECO's revised electric POR program requires PECO to purchase the customer accounts receivable of EGSs that participate in the electric customer choice program and have elected consolidated billing by PECO. The revised POR program became effective on January 1, 2011 and provides for full recovery of PECO's system implementation costs for program administration through a temporary discount on purchased receivables. The revised POR program was approved by the PAPUC on June 16, 2010 and allows PECO to terminate electric service to customers beginning January 1, 2011, based on unpaid charges for EGS service, and permits recovery of uncollectible accounts expense from customers through electric distribution rates. As of September 30, 2011, the balance of receivables purchased under the revised POR program was $53 million. Receivables purchased under the previous POR program were $3 million as of December 31, 2010. The increase in the POR receivable balance is a result of increased customer choice program participation following the expiration of the transition period. Prior to participation in the customer choice program, these receivables would have been recorded in customer accounts receivable. Receivables purchased under both programs are classified in other accounts receivable, net on Exelon and PECO's Consolidated Balance Sheets.

Smart Meter and Smart Grid Investments (Exelon and PECO). In April 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan under which PECO will install more than 1.6 million smart meters and deploy advanced communication networks over a 10-year period. In 2010, PECO entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA. Under the SGIG, PECO has been awarded $200 million, the maximum grant allowable under the program, for its SGIG project — Smart Future Greater Philadelphia. In total, through 2020, PECO plans to spend up to a total of $650 million on its smart grid and smart meter infrastructure. The $200 million SGIG is being used to reduce the impact of these investments on PECO ratepayers.

During the nine months ended September 30, 2011, PECO received $52 million in reimbursements from the DOE. As of September 30, 2011, PECO's outstanding receivable from the DOE for reimbursable costs was $16 million, which has been recorded in other accounts receivable, net on Exelon's and PECO's Consolidated Balance Sheets.

On April 15, 2011, the PAPUC issued the order approving the joint petition for partial settlement of the initial dynamic pricing and customer acceptance plan and ruled that the administrative costs be recovered from default service customers through the GSA. PECO plans to file for approval of a universal meter deployment plan for its remaining customers in 2012.

Energy Efficiency Programs (Exelon and PECO). On July 15, 2011, PECO filed a petition to make adjustments to its PAPUC-approved four-year EE&C Plan, which began in 2009. The plan includes a CFL program, weatherization programs, an energy efficiency appliance rebate and recycling program and rebates for non-profit, educational, governmental and business customers, customer incentives for energy management programs and incentives to help customers reduce energy demand during peak periods. The filing noted that PECO has exceeded the 1% energy use reduction target required by May 31, 2011; the adjustments, which were approved by the PAPUC on August 18, 2011, will allow PECO to meet its May 31, 2013 targets for energy use and energy demand reductions, while remaining within its approved plan budget.

Alternative Energy Portfolio Standards (Exelon and PECO). The AEPS Act mandated that, beginning in 2011, certain percentages of electric energy sold to Pennsylvania retail electric customers shall be generated from certain alternative energy resources as measured in AECs. The requirement for electric energy that must come from Tier I alternative energy resources ranges from approximately 3.5% to 8.0% and the requirement for Tier II alternative energy resources ranges from 6.2% to 10.0%. The required compliance percentages incrementally increase each annual compliance period, which is from June 1 through May 31, until May 31, 2021. On February 10, 2011, the PAPUC approved PECO's petition related to the procurement of supplemental AECs and Tier II AECs and the sale of excess AECs through independent third party auctions or brokers. On May 10, 2011, the PAPUC approved PECO's procurement of 340,000 Tier II AECs that will be used to meet AEPS Act obligations in the 2011 and 2012 compliance years.

The AECs procured prior to the 2011 compliance year were banked and are anticipated to be used to meet AEPS obligations over two compliance periods ending May 2013 in accordance with the petition approved by the PAPUC on February 10, 2011. Administrative costs and the costs of the banked AECs are being recovered with a return on the unamortized balance over a twelve month period that began January 1, 2011. All AEPS administrative costs and costs of AECs incurred after December 31, 2010 are being recovered on a full and current basis through a rider.

Natural Gas Choice Supplier Tariff (Exelon and PECO). On March 11, 2011, PECO filed tariff supplements to its Gas Choice Supplier Coordination Tariff and the Retail Gas Service Tariff to address the new licensing requirements for natural gas suppliers outlined in the PAPUC's final rulemaking order that became effective January 1, 2011. The new licensing requirements broaden the types of collateral that PECO can obtain to mitigate its risk related to a natural gas choice supplier default and PECO's ability to adjust collateral when material changes in supplier creditworthiness exist.

Investigation of Pennsylvania Retail Electricity Market (Exelon and PECO). On July 28, 2011, the PAPUC issued an order outlining the next steps in its investigation into the status of competition in Pennsylvania's retail electric market. The PAPUC found that the existing default service model presents substantial impediments to the development of a vibrant retail market in Pennsylvania and directed the Office of Competitive Markets Oversight to evaluate potential intermediate and long-term structural changes to the default service model. On October 14, 2011, the PAPUC issued for comment tentative recommendations to guide the state's electric distribution companies in developing upcoming default service plans. A final order is expected to be issued in December 2011. Final guidance on long-term structural changes is expected to be issued in 2012.

Federal Regulatory Matters

Annual Transmission Formula Rate Update (Exelon and ComEd). ComEd's most recent annual formula rate update filed in May 2011 reflects actual 2010 expenses and investments plus forecasted 2011 capital additions. The update resulted in a revenue requirement of $438 million offset by a $16 million reduction related to the true-up of 2010 actual costs for a net revenue requirement of $422 million. This compares to the May 2010 updated net revenue requirement of $416 million. The increase in the revenue requirement was primarily driven by the Illinois income tax statutory rate change enacted in January 2011. The 2011 net revenue requirement became effective June 1, 2011 and is recovered over the period extending through May 31, 2012. 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 9.10%, a decrease from the 9.27% return previously authorized. The decrease in return was primarily due to lower interest rates on ComEd's long-term debt outstanding. As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.5% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the formula transmission rate is currently capped at 55%.

Market-Based Rates (Exelon, Generation, ComEd and PECO). Generation, ComEd and PECO are public utilities for purposes of the Federal Power Act and are required to obtain FERC's acceptance of rate schedules for wholesale electricity sales. Currently, Generation, ComEd and PECO have authority to execute wholesale electricity sales at market-based rates. In the most recent market power analysis for the PJM region, Generation informed FERC that its market share data in PJM would change beginning in 2011, when Generation's contract for PECO's full requirements for capacity and energy expired. The FERC Staff asked for a letter describing the amount of capacity affected by the PECO contract expiration and alternative transactions, which Generation filed on March 21, 2011. The impact of that change, as well as that of any new sales contracts or other intervening changes in Generation's market share, will be reflected in the next updated market share screen analysis due to be filed at the end of 2013. In the meantime, under FERC's rules and precedent, any market power concerns would be obviated by FERC-approved RTO market monitoring and mitigation program in PJM. On June 22, 2011, FERC issued an order confirming Generation's continued authority to charge market based rates, stating that any market power concerns are adequately addressed by PJM's monitoring and mitigation program.

PJM Minimum Offer Price Rule (Exelon and Generation). PJM's capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. On February 1, 2011, in response to the enactment of New Jersey Senate Bill 2381, Generation joined a group of generating companies, PJM Power Providers Group (P3), in filing a complaint asking FERC to revise PJM's MOPR to mitigate this exercise of buyer market power. In response to P3's complaint, PJM filed a tariff amendment on February 11, 2011, to improve the MOPR. PJM's filing differs in some ways from P3's proposal, but in general P3 supports PJM's filing. P3 and PJM requested that FERC act on the proposed tariff amendment prior to the May 2011 capacity auction. A number of state regulators and consumer groups have opposed the tariff changes, but these changes are in line with recent FERC orders regarding capacity markets in the New York and New England ISOs. On April 12, 2011, FERC issued an order revising PJM's MOPR to mitigate the exercise of buyer market power. Included in the FERC order was a revision to the MOPR whereby a subsidized plant cannot submit a bid into the auction for less than 90% of the cost of new entry of a plant of that type, unless the unit can justify a lower bid based on its costs. The minimum offer limitation continues until a unit clears the base residual RPM auction for the first time. After a unit clears once, it may bid in at any price, including zero. This may help reduce the magnitude of artificial suppression of capacity auction prices created by the actions of state regulators such as the capacity legislation in New Jersey. A number of parties filed for rehearing of the FERC order on several different issues, including the question of whether the minimum price mitigation should apply to load serving entities that self-supply capacity. FERC scheduled the issue for consideration at a technical conference, while rehearing is pending.

License Renewals (Exelon and Generation) On August 18, 2009, PSEG submitted applications to the NRC to extend the operating licenses of Salem Units 1 and 2 by 20 years. Exelon is a 42.59% owner of the Salem Units. On June 30, 2011, the NRC issued the renewed operating licenses for Salem Units 1 and 2 expiring in 2036 and 2040, respectively.

On June 22, 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years. The NRC is expected to spend a total of 22 to 30 months to review the applications before making a decision. The current operating licenses for Limerick Units 1 and 2 expire in 2024 and 2029, respectively.

Regulatory Assets and Liabilities (Exelon, ComEd and PECO)

Exelon, ComEd and PECO 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 and PECO as of September 30, 2011 and December 31, 2010. For additional information on the specific regulatory assets and liabilities, refer to Note 2 of the 2010 Form 10-K.

September 30, 2011	Exelon	ComEd	PECO
Regulatory assets			
Pension and other postretirement benefits	$2,671	$ —	$ 8
Deferred income taxes	1,161	70(a)	1,091
AMI and smart meter program expenses	31	9	22
Debt costs	105	93	12
Severance(b)	69	69	—
Asset retirement obligations	74	50	24
MGP remediation costs	161	115	46
RTO start-up costs	8	8	—
Financial swap with Generation — noncurrent	—	247	—
Renewable energy and associated RECs — noncurrent(c)	48	48	—
DSP Program costs	6	—	6
Other	47	24	24
Noncurrent regulatory assets	4,381	733	1,233
Financial swap with Generation — current	—	415	—
Under-recovered energy and transmission costs	28	24	4(d)
DSP Program electric procurement contracts(e)	1	—	3
Renewable energy and associated RECs — current(c)	2	2	—
Current regulatory assets	31	441	7
Total regulatory assets	$4,412	$1,174	$1,240
Regulatory liabilities			
Nuclear decommissioning(f)	$2,077	$1,748	$ 329
Removal costs	1,239	1,239	—
Refund of PURTA taxes	1	—	1
Energy efficiency and demand response programs	108	46	62
Over-recovered uncollectible accounts	5	5	—
Electric transmission and distribution tax repairs	171	—	171
Noncurrent regulatory liabilities	3,601	3,038	563
Over-recovered energy and transmission costs	50	17	33(g)
Over-recovered universal service fund costs(h)	3	—	3
Over-recovered AEPS costs	7	—	7
Current regulatory liabilities	60	17	43
Total regulatory liabilities	$3,661	$3,055	$ 606

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

December 31, 2010	Exelon	ComEd	PECO
Regulatory assets			
Pension and other postretirement benefits	$2,763	$ —	$ 13
Deferred income taxes	852	23	829
AMI and smart meter program expenses	17	—	17
Debt costs	123	108	15
Severance	74	74	—
Asset retirement obligations	86	61	25
MGP remediation costs	149	110	39
RTO start-up costs	10	10	—
Under-recovered uncollectible accounts	14	14	—
Financial swap with Generation — noncurrent	—	525	—
DSP Program costs	7	—	7
Other	45	22	23
Noncurrent regulatory assets	4,140	947	968
Financial swap with Generation — current	—	450	—
Under-recovered energy and transmission costs	6	6	—
DSP Program electric procurement contracts(e)	4	—	9
Current regulatory assets	10	456	9
Total regulatory assets	$4,150	$1,403	$977
Regulatory liabilities			
Nuclear decommissioning(f)	$2,267	$1,892	$375
Removal costs	1,211	1,211	—
Renewable energy and associated RECs — noncurrent(c)	4	4	—
Refund of PURTA taxes	4	—	4
Energy efficiency and demand response programs	69	31	38
Other	—	(1)	1
Noncurrent regulatory liabilities	3,555	3,137	418
Over-recovered energy and transmission costs	44	19	25(g)
Current regulatory liabilities	44	19	25
Total regulatory liabilities	$3,599	$3,156	$443

(a) Includes a regulatory asset at ComEd recorded pursuant to the 2010 Rate Case order for the recovery of costs related to the passage of the Health Care Reform Acts in 2010. Also includes a regulatory asset at ComEd recorded as a result of a change in the Illinois corporate tax rate during January 2011. See Note 8 — Income Taxes for additional information.

(b) Includes $13 million at ComEd recorded pursuant to the 2010 Rate Case order to recover costs related to the 2009 Exelon restructuring plan.

(c) These amounts represent the unrealized losses (regulatory asset) or gains (regulatory liability) on 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers at ComEd. See Note 6 — Derivative Financial Instruments for additional information.

(d) Relates to the under-recovered transmission costs.

(e) As of September 30, 2011 and December 31, 2010, PECO recorded a regulatory asset to offset the current mark-to-market liability recorded for derivative block contracts. See Note 6 — Derivative Financial Instruments for additional information.

(f) These amounts represent estimated future nuclear decommissioning costs that are less than the associated NDT fund assets. These regulatory liabilities have an equal and offsetting noncurrent receivable from affiliate at ComEd and PECO, and a noncurrent payable to affiliate recorded at Generation equal to the total regulatory liability at Exelon, ComEd and PECO. See Note 9 — Nuclear Decommissioning for additional information on the NDT fund activity.

(g) Includes $14 million related to the over-recovered natural gas costs under the PGC and $19 related to the over-recovered electric supply costs under the GSA.

(h) The universal services fund cost is a recovery mechanism that allows for PECO to recover discounts issued to electric and gas customers enrolled in assistance programs. As of September 30, 2011, PECO was over-recovered for its electric and gas programs.

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

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Operating and Maintenance for Regulatory Required Programs (Exelon, ComEd and PECO)

The following tables set forth costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates for ComEd and PECO for the three and nine months ended September 30, 2011 and 2010. An equal and offsetting amount has been reflected in operating revenues during the periods.

For the Three Months Ended September 30, 2011	Exelon	ComEd	PECO
Energy efficiency and demand response programs	$ 52	$ 41	$ 11
Smart meter program	3	—	3
Purchased power administrative costs	3	2	1
Consumer education program	1	—	1
Total operating and maintenance for regulatory required programs	$ 59	$ 43	$ 16

For the Nine Months Ended September 30, 2011	Exelon	ComEd	PECO
Energy efficiency and demand response programs	$ 122	$ 80	$ 42
Smart meter program	7	—	7
Purchased power administrative costs	7	4	3
Consumer education program	2	—	2
Total operating and maintenance for regulatory required programs	$ 138	$ 84	$ 54

For the Three Months Ended September 30, 2010	Exelon	ComEd	PECO
Energy efficiency and demand response programs	$ 35	$ 21	$ 14
Purchased power administrative costs	1	1	—
Consumer education program	1	—	1
Total operating and maintenance for regulatory required programs	$ 37	$ 22	$ 15

For the Nine Months Ended September 30, 2010	Exelon	ComEd	PECO
Energy efficiency and demand response programs	$ 93	$ 59	$ 34
Purchased power administrative costs	3	3	—
Consumer education program	2	—	2
Total operating and maintenance for regulatory required programs	$ 98	$ 62	$ 36

4. Merger and Acquisitions (Exelon and Generation)

Proposed Merger with Constellation Energy Group, Inc. (Exelon)

On April 28, 2011, Exelon and Constellation Energy Group, Inc. (Constellation) announced that they signed an agreement and plan of merger to combine the two companies in a stock-for-stock transaction. Under the merger agreement, Constellation's shareholders will receive 0.930 shares of Exelon common stock in exchange for each share of Constellation common stock. Based on Exelon's closing share price on April 27, 2011, Constellation shareholders would receive $7.9 billion in total equity value. The resulting company will retain the Exelon name and be headquartered in Chicago.

The transaction must be approved by the shareholders of both Exelon and Constellation. Completion of the transaction is also conditioned upon approval by the FERC, NRC, Maryland Public Service Commission (MDPSC), the New York Public Service Commission, the Public Utility Commission of Texas (PUCT), and other state and federal regulatory bodies. The companies have proposed to divest three Constellation generating stations located in PJM, which is the only market where there is a material overlap of generation owned by both companies. These stations, Brandon Shores and H.A. Wagner in Anne Arundel County, Md., and C.P. Crane in Baltimore County, Md., 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 the merged company, 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 the merged company will bid its units into the PJM markets. In addition, under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act), the transaction cannot be completed until Exelon has made required notifications and given certain information and materials to the FTC and/or the Antitrust Division of the DOJ and until specified waiting period requirements have expired. During the second quarter, Exelon and Constellation filed applications with FERC, the MDPSC, the New York State Public Service Commission and the PUCT seeking approval of the transaction. Exelon and Constellation also filed an application with the NRC for indirect transfer of Constellation's nuclear operating licenses and filed notifications with the FTC and DOJ in compliance with the requirements of the HSR Act. During the third quarter, Exelon and Constellation received approval of the transaction from the PUCT.

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 is disclosed and sought rescission of the proposed merger. During the third quarter, the parties to the suits reached an agreement in principle to settle the suits through additional disclosures to Constellation shareholders. The settlement is subject to court approval.

Through September 30, 2011, Exelon has incurred approximately $37 million of expense associated with the transaction, primarily related to fees incurred as part of the acquisition. As part of the application for approval of the merger by MDPSC, Exelon and Constellation have proposed a package of benefits to Baltimore Gas and Electric Company customers, the City of Baltimore and the state of Maryland, which results in a direct investment in the state of Maryland of more than $250 million. Under the merger agreement, in the event Exelon or Constellation terminates the merger agreement to accept a superior proposal, or under certain other circumstances, Exelon or Constellation, as applicable, would be required to pay a termination fee of $800 million in the case of a termination fee payable by Exelon to Constellation or a termination fee of $200 million in the case of a termination fee payable by Constellation to Exelon. The companies anticipate closing the transaction in early 2012.

Acquisition of Antelope Valley Solar Ranch One (Exelon and Generation)

On September 30, 2011, Exelon announced the completion of its acquisition of all of the interest in Antelope Valley Solar Ranch One (Antelope Valley), a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, Inc., which developed and will build, operate, and maintain the project. Construction has started, with the first portion of the project expected to come online in late 2012 and full operation planned for late 2013. The acquisition builds on the Exelon commitment to clean energy as part of Exelon 2020, a business and environmental strategy to eliminate the equivalent of Exelon's 2001 carbon footprint. The project has a 25-year PPA, approved by the California Public Utilities Commission, with Pacific Gas & Electric Company for the full output of the plant.

Exelon expects to invest up to $713 million in equity in the project through 2013. The DOE's Loan Programs Office issued a guarantee for up to $646 million for a non-recourse loan from the Federal Financing

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

Bank to support the financing of the construction of the project. The purchase agreement contains a provision that First Solar, Inc. will repurchase Antelope Valley if initial funding of the loan does not occur by the end of 2011. See Note 7 — Debt and Credit Agreements for additional information on the loan guaranteed by the DOE.

Consistent with the applicable accounting guidance, the fair value of Antelope Valley's assets and liabilities were determined as of the acquisition date. The fair value of assets acquired and liabilities assumed was determined through the use of significant estimates and assumptions that are judgmental in nature. Some of the more significant estimates and assumptions used include: projected future cash flows (including the amount and timing); discount rates reflecting the risk inherent in the future cash flows; and future market prices based on the Market Price Referent (MPR) established by the California PUC for renewable energy resources. Generation did not record any goodwill related to the acquisition of Antelope Valley.

The following table summarizes the fair value of consideration transferred to acquire Antelope Valley and the fair value of identified assets and liabilities assumed as of the acquisition date:

Fair Value of Consideration Transferred

Cash	$ 75
Total fair value of consideration transferred	$ 75
Recognized Amounts of Identifiable Assets Acquired and Liabilities Assumed	
Intangible asset	$ 190
Property, plant and equipment	15
Payable to First Solar, Inc.	(135)
Other Assets	5
Total net identifiable assets	$ 75

Accounting guidance requires that the acquirer must recognize separately identifiable intangible assets in the application of purchase accounting. Upon completion of the development project, all of the output will be sold under the PPA with Pacific Gas & Electric. The excess of the contract price of the PPA over forecasted MPR-based market prices was recognized as an intangible asset. Generation determined that the acquisition-date fair value of the intangible asset was approximately $190 million, which was recorded in other deferred debits and other assets within Exelon and Generation's Consolidated Balance Sheets. While Generation expects to perform under the PPA once the construction of this project is complete, there is a risk of impairment if the project does not reach commercial operation. The valuation of the acquired intangible asset was estimated by applying the income approach, which is based upon discounted projected future cash flows associated with the PPA. That measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include forecasted MRP-based market prices and discount rate. The intangible asset will be amortized as revenue is earned over the term of the underlying PPA. The amortization expense will be reflected as a decrease in operating revenue within Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income. Exelon concluded that the remaining, yet-to-be paid $135 million in consideration was embedded in the amounts payable under the Engineering, Procurement, Construction (EPC) agreement for First Solar, Inc. to construct the solar facility. For accounting purposes, this aspect of the transaction is considered to be akin to a "seller financing" arrangement. As such, Exelon recorded a liability of $135 million associated with the portion of the future payments to First Solar, Inc. under the EPC agreement to reflect Generation's implicit amounts due First Solar, Inc. for the remainder of the value of the net assets acquired. The $135 million payable to First Solar, Inc. will be relieved as Generation makes payments for costs incurred over the project construction period.

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

In 2011, Exelon and Generation incurred approximately $8 million of acquisition-related costs associated with this transaction. These costs are included within operating and maintenance expense in Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income.

Acquisition of Wolf Hollow, LLC (Exelon and Generation)

On August 24, 2011, Generation completed the acquisition of all of the equity interests of Wolf Hollow, LLC (Wolf Hollow), a combined-cycle, natural gas-fired power plant in north Texas, pursuant to which Generation added 720 MWs of capacity within the ERCOT power market, which will further reduce Exelon's carbon footprint. The acquisition builds on the Exelon commitment to clean energy as part of Exelon 2020. In connection with the acquisition, Generation terminated and settled its existing long-term PPA with Wolf Hollow, resulting in a gain of approximately $6 million, which is included within operating revenues (other revenue) in Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income.

The fair value of assets acquired and liabilities assumed was determined based upon the use of significant estimates and assumptions that are judgmental in nature. Some of the more significant estimates and assumptions used include projected future cash flows (including the timing and amounts of plant operating costs), discount rates reflecting the risk inherent in the future cash flows and future power and fuel market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and the duration of the liabilities assumed. The PPA gain was calculated based on projected PPA cash flows relative to market power prices and the underlying terms of the agreement. Generation recognized an approximately $36 million non-cash bargain purchase gain (i.e., negative goodwill). The gain was included within other, net in Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income. Working capital is subject to a 180-day adjustment period.

The following table summarizes the fair value of consideration transferred to acquire Wolf Hollow and the value of identified assets and liabilities assumed as of the acquisition date:

Fair Value of Consideration Transferred

Total fair value of consideration transferred	$311
Less: Gain on PPA settlement	6
Cash	$305
Recognized Amounts of Identifiable Assets Acquired and Liabilities Assumed	
Property, plant and equipment	$347
Inventory	5
Working capital, net	(5)
Total net identifiable assets	$347
Bargain purchase gain	$ 36

Consistent with the applicable accounting guidance, the fair value of Wolf Hollow's assets and liabilities was determined as of the August 24, 2011 acquisition date. Increases in observable forward market power prices since the May 2011 transaction announcement date, primarily reflecting the impact on the Texas power markets of the Cross-State Air Pollution Rule (CSAPR) final regulations issued by the EPA in July 2011, as well as sustained hot weather in Texas, resulted in an increase in fair value of the net assets as of the acquisition date, resulting in the bargain purchase gain.

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

The fair value of the assets acquired included receivables for insurance claims of $14 million shown in working capital above. This amount represents insured repair costs incurred prior to the acquisition date, less the applicable deductible. As of September 30, 2011, approximately $14 million remains outstanding, which Generation expects to collect by the end of 2011.

Wolf Hollow's revenue and operating income contribution to Exelon and Generation for the period from August 25, 2011 to September 30, 2011 was approximately $16 million and $4 million, respectively. The unaudited pro forma results for Exelon and Generation as if the Wolf Hollow acquisition occurred on January 1, 2010 were not materially different from Exelon and Generation's financial results for the three and nine months ended September 30, 2011 and 2010. Exelon and Generation incurred approximately $4 million of acquisition-related costs associated with this transaction. These costs are included within operating and maintenance expense in Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income.

Acquisition of John Deere Renewables (Exelon and Generation)

On December 9, 2010, Generation completed the acquisition of all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind), a leading operator and developer of wind power. Under the terms of the agreement, Generation acquired 735 MWs of installed, operating wind capacity located in eight states. The acquisition builds on Exelon's commitment to renewable energy as part of Exelon 2020.

The fair value of assets acquired and liabilities assumed was determined based upon the use of significant estimates and assumptions that are judgmental in nature. Some of the more significant estimates and assumptions used include: projected future cash flows (including timing); discount rates reflecting the 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 the duration of the liabilities assumed. Generation did not record any goodwill related to the acquisition of Exelon Wind.

The following table summarizes the fair value of consideration transferred to acquire Exelon Wind and the value of identified assets and liabilities assumed as of the acquisition date:

Fair Value of Consideration Transferred

Cash(a)	$893
Contingent consideration	32
Total fair value of consideration transferred	$925
Recognized amounts of identifiable assets acquired and liabilities assumed	
Property, plant and equipment	$700
Intangible assets	224
Working capital, net	18
Asset retirement obligations	(13)
Noncontrolling interest	(3)
Other	(1)
Total net identifiable assets	$925

(a) On September 30, 2010, Generation issued $900 million of senior notes, the proceeds of which were used to fund the acquisition.

The contingent consideration arrangement requires that Generation pay up to $40 million related to three individual projects with an aggregate capacity of 230 MWs, which are currently in advanced stages of development or under construction, upon meeting certain contractual commitments related to the commencement of construction of each project. The fair value of the contingent consideration arrangement of $32 million was determined as of the acquisition date based upon a weighted average probability of meeting certain contractual commitments related to the commencement of construction of each project, which is considered an unobservable (Level 3) input pursuant to applicable accounting guidance. During the third quarter of 2011, $16 million of contingent consideration was paid to Deere & Company for one of the projects and the probability of a second project beginning construction was increased to 100%. As a result, $2 million expense was recorded in operating and maintenance expense within Exelon and Generation’s Consolidated Statements of Operations and Comprehensive Income and the contingent consideration included within other current liabilities within Exelon and Generation’s Consolidated Balance Sheets was adjusted to $10 million to reflect the full expected contingent payment related to the Harvest II project. The remaining $8 million of contingent consideration is included in other deferred credits and other liabilities within Exelon and Generation’s Consolidated Balance Sheets.

The fair value of the assets acquired included customer receivables of $18 million. There are no outstanding customer receivables that were acquired in the Exelon Wind transaction.

The $3 million noncontrolling interest represents the noncontrolling members’ proportionate share in the fair value of the assets acquired and liabilities assumed in the transaction.

The unaudited pro forma results for Exelon and Generation prepared as if the Exelon Wind acquisition occurred on January 1, 2009 were not materially different from Exelon and Generation’s financial results for the three and nine months ended September 30, 2010.

Accounting guidance requires that the acquirer must recognize separately identifiable intangible assets in the application of purchase accounting. Most of the output of the acquired wind turbines has been sold under PPA contracts. The excess of the contract price of the PPAs over market prices was recognized as intangible assets. Generation determined that the estimated acquisition-date fair value of the intangible assets was approximately $224 million, which was recorded in other deferred debits and other assets within Exelon and Generation’s Consolidated Balance Sheets. Included in this amount is $48 million related to the PPAs for the projects that are in the advanced stage of development. While Generation expects to perform under the PPAs once the construction of these projects is complete, there is a risk of impairment if the projects do not reach commercial operation. The valuation of the acquired intangible assets was estimated by applying the income approach, which is based upon discounted projected future cash flows associated with the PPA contracts. That measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include forecasted power prices and discount rate. The intangible assets are amortized on a straight-line basis over the period in which the associated contract revenues are recognized. Generation determined that the unit of production amortization method would best reflect when the intangible assets’ economic benefits would be consumed; however, the straight-line method approximates the equivalent of the unit of production method on an annual basis. The amortization expense is reflected as a decrease in operating revenue within Exelon and Generation’s Consolidated Statements of Operations and Comprehensive Income. Amortization expense related to Exelon and Generation’s acquired intangible assets for the three and nine months ended September 30, 2011 was $3 million and $9 million, respectively.

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

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Exelon's and Generation's other acquired intangible assets, included in deferred debits and other assets in the Consolidated Balance Sheets, consisted of the following as of September 30, 2011:

				Estimated amortization expense				
Generation	Gross	Accumulated Amortization	Net	Remainder of 2011	2012	2013	2014	2015
Exelon Wind	$224	$ (10)	$214	$ 3	$13	$14	$14	$14
Antelope Valley	190	—	190	—	18	39	24	17
Total intangible assets	$414	$ (10)	$404	$ 3	$31	$53	$38	$31

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

Non-Derivative Financial Assets and Liabilities. As of September 30, 2011 and December 31, 2010, the Registrants' carrying amounts of cash and certain cash equivalents, accounts receivable, accounts payable, short term notes payable and accrued liabilities are representative of fair value because of the short-term nature of these instruments.

Fair Value of Financial Liabilities Recorded at the Carrying Amount

Exelon

The carrying amounts and fair values of Exelon's long-term debt, SNF obligation and preferred securities as of September 30, 2011 and December 31, 2010 were as follows:

	September 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt (including amounts due within one year)	$13,414	$14,889	$12,213	$12,960
Long-term debt to financing trusts	390	355	390	350
SNF obligation	1,019	846	1,018	876
Preferred securities of subsidiary	87	75	87	68

The fair value of long-term debt is determined using a valuation model, which is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. The fair value of preferred securities of subsidiaries is determined using observable market prices as these securities are actively traded. The carrying amount of Exelon and Generation's SNF obligation resulted from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. Exelon and Generation's obligation to the DOE accrues at the 13-week Treasury rate. When determining the fair value of the obligation, the future carrying amount of the SNF obligation in 2020 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The future compounded obligation amount is discounted back to present using the prevailing Treasury rate for a long-term obligation with an estimated maturity date of 2020 (after being adjusted for Generation's credit risk).

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

Generation

The carrying amounts and fair values of Generation's long-term debt and spent nuclear fuel obligations as of September 30, 2011 and December 31, 2010 were as follows:

	September 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt (including amounts due within one year)	$ 3,677	$4,053	$ 3,679	$3,792
SNF obligation	1,019	846	1,018	876

ComEd

The carrying amounts and fair values of ComEd's long-term debt as of September 30, 2011 and December 31, 2010 were as follows:

	September 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt (including amounts due within one year)	$ 6,202	$6,920	$ 5,001	$5,411
Long-term debt to financing trust	206	183	206	176

PECO

The carrying amounts and fair values of PECO's long-term debt and preferred securities as of September 30, 2011 and December 31, 2010 were as follows:

	September 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt (including amounts due within one year)	$ 2,222	$2,483	$ 2,222	$2,402
Long-term debt to financing trusts	184	172	184	173
Preferred securities	87	75	87	68

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, exchange-based derivatives, mutual funds 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 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.

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

There were no significant transfers between Level 1 and Level 2 during the nine months ended September 30, 2011.

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, 2011 and December 31, 2010:

As of September 30, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 1,485	$ —	$ —	$ 1,485
Nuclear decommissioning trust fund investments				
Cash equivalents	320	20	—	340
Equity securities(b)	1,147	—	—	1,147
Commingled funds(c)	—	1,791	—	1,791
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	598	91	—	689
Debt securities issued by states of the United States and political subdivisions of the states	—	549	—	549
Corporate debt securities	—	701	—	701
Federal agency mortgage-backed securities	—	901	—	901
Commercial mortgage-backed securities (non-agency)	—	116	—	116
Residential mortgage-backed securities (non-agency)	—	5	—	5
Other debt obligations	—	64	6	70
Nuclear decommissioning trust fund investments subtotal(d)	2,065	4,238	6	6,309
Pledged assets for Zion Station decommissioning				
Equity securities	43	—	—	43
Commingled funds(c)	—	67	—	67
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	114	22	—	136
Debt securities issued by states of the United States and political subdivisions of the states	—	49	—	49
Corporate debt securities	—	291	—	291
Federal agency mortgage-backed securities	—	123	—	123
Commercial mortgage-backed securities (non-agency)	—	12	—	12
Private equity	—	—	38	38
Other debt obligations	—	2	—	2
Pledged assets for Zion Station decommissioning subtotal(e)	157	566	38	761
Rabbi trust investments				
Mutual funds(f)	34	—	—	34
Rabbi trust investments subtotal	34	—	—	34
Mark-to-market derivative assets				
Cash flow hedges	—	413	—	413
Other derivatives	—	1,209	15	1,224
Proprietary trading	—	165	52	217
Effect of netting and allocation of collateral(g)	(1)	(1,058)	(17)	(1,076)
Mark-to-market assets(h)	(1)	729	50	778
Total assets	3,740	5,533	94	9,367
Liabilities				
Mark-to-market derivative liabilities				
Cash flow hedges(i)	—	(141)	—	(141)
Other derivatives	(1)	(651)	(67)	(719)
Proprietary trading	—	(161)	(26)	(187)
Effect of netting and allocation of collateral(g)	1	910	18	929
Mark-to-market liabilities(h)	—	(43)	(75)	(118)
Deferred compensation	—	(69)	—	(69)
Total liabilities	—	(112)	(75)	(187)
Total net assets	$ 3,740	$ 5,421	$ 19	$ 9,180

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

As of December 31, 2010	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 1,473	$ —	$ —	$ 1,473
Nuclear decommissioning trust fund investments				
Cash equivalents	1	—	—	1
Equity securities(b)	1,513	—	—	1,513
Commingled funds(c)	—	2,212	—	2,212
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	504	96	—	600
Debt securities issued by states of the United States and political subdivisions of the states	—	451	—	451
Corporate debt securities	—	619	—	619
Federal agency mortgage-backed securities	—	804	—	804
Commercial mortgage-backed securities (non-agency)	—	114	—	114
Residential mortgage-backed securities (non-agency)	—	14	—	14
Other debt obligations	—	48	—	48
Nuclear decommissioning trust fund investments subtotal(d)	2,018	4,358	—	6,376
Pledged assets for Zion decommissioning				
Equity securities	84	—	—	84
Commingled funds(c)	—	132	—	132
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	166	12	—	178
Debt securities issued by states of the United States and political subdivisions of the states	—	45	—	45
Corporate debt securities	—	263	—	263
Federal agency mortgage-backed securities	—	102	—	102
Commercial mortgage-backed securities (non-agency)	—	14	—	14
Other debt obligations	—	2	—	2
Pledged assets for Zion Station decommissioning subtotal(e)	250	570	—	820
Rabbi trust investments				
Mutual funds(f)	36	—	—	36
Rabbi trust investments subtotal	36	—	—	36
Mark-to-market derivative assets				
Cash flow hedges	—	724	12	736
Other derivatives	2	1,709	57	1,768
Proprietary trading	—	235	46	281
Effect of netting and allocation of collateral(g)	(3)	(1,848)	(38)	(1,889)
Mark-to-market assets(h)	(1)	820	77	896
Total assets	3,776	5,748	77	9,601
Liabilities				
Mark-to-market derivative liabilities				
Cash flow hedges	—	(45)	—	(45)
Other derivatives	(2)	(667)	(29)	(698)
Proprietary trading	—	(233)	(21)	(254)
Effect of netting and allocation of collateral(g)	1	914	23	938
Mark-to-market liabilities(h)	(1)	(31)	(27)	(59)
Deferred compensation	—	(76)	—	(76)
Total liabilities	(1)	(107)	(27)	(135)
Total net assets	$ 3,775	$ 5,641	$ 50	$ 9,466

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

(b) Generation's NDT funds hold equity portfolios whose performance is benchmarked against established indices.

(c) Generation's NDT funds and Zion Station decommissioning pledged assets own commingled funds that invest in equity securities. Generation's NDT funds and Zion Station decommissioning pledged assets also own commingled funds that invest in fixed income securities. The commingled funds seek to out-perform certain established indices.

(d) Excludes net (liabilities) assets of $(83) million and $32 million at September 30, 2011 and December 31, 2010, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(e) Excludes net assets of $2 million and $4 million at September 30, 2011 and December 31, 2010. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

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

(f) Excludes $24 million and $25 million of the cash surrender value of life insurance investments at September 30, 2011 and December 31, 2010, respectively.

(g) Includes collateral postings received from counterparties. Collateral received from counterparties, net of collateral (paid) to counterparties, totaled $148 million and $(1) million allocated to Level 2 and Level 3 mark-to-market derivatives, respectively, as of September 30, 2011. Collateral received from counterparties, net of collateral (paid) to counterparties, totaled $2 million, $934 million and $15 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2010.

(h) The Level 3 balance does not include current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $415 million and $247 million at September 30, 2011 and $450 million and $525 million at December 31, 2010, respectively, related to the fair value of Generation's financial swap contract with ComEd; and current assets for Generation and current liabilities for PECO of $2 million and $5 million at September 30, 2011 and December 31, 2010, respectively, related to the fair value of Generation's block contracts with PECO, which eliminate upon consolidation in Exelon's Consolidated Financial Statements.

(i) Excludes $13 million mark-to-market liability relating to an interest rate swap in connection with the DOE loan guarantee financing for Antelope Valley discussed in Note 6 — Derivative Financial Instruments. The fair value of the swap would be considered a Level 2 liability.

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 and 2010:

Three Months Ended September 30, 2011	Nuclear Decommissioning Trust Fund Investment	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Total
Balance as of June 30, 2011	$ —	$ 34	$ (16)	$ 18
Total realized / unrealized (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 — Asset	—	—	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 gains (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 Investment	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Total
Balance as of December 31, 2010	$ —	$ —	$ 50	$ 50
Total realized / unrealized (losses)				
Included in other comprehensive income	—	—	(27)(b)	(27)
Included in regulatory assets	—	—	(51)	(51)
Change in collateral	—	—	15	15
Purchases, sales, issuances and settlements				
Purchases	6	60	4	70
Sales	—	(22)	—	(22)
Transfers out of Level 3 — Asset	—	—	(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) Includes $7 million and $4 million of decreases in fair value and 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 nine months ended September 30, 2011 . All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

Three Months Ended September 30, 2010	Nuclear Decommissioning Trust Fund Investments(d)	Mark-to-Market Derivatives	Total
Balance as of June 30, 2010	$ 1	$ 67	$ 68
Total realized / unrealized gains (losses)			
Included in income	—	30(a)	30
Included in other comprehensive income	—	14(b)	14
Change in collateral	—	(14)	(14)
Purchases, sales, issuances and settlements			
Purchases	12	4	16
Sales	(1)	—	(1)
Transfers out of Level 3 — Liability	—	3	3
Balance as of September 30, 2010	$ 12	$ 104	$ 116
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the three months ended September 30, 2010	$ —	$ 34	$ 34

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

Nine Months Ended September 30, 2010	Servicing Liability	Nuclear Decommissioning Trust Fund Investments(d)	Mark-to-Market Derivatives	Total
Balance as of December 31, 2009	$ (2)	$ —	$ (44)	$ (46)
Total realized / unrealized gains (losses)				
Included in income	2(c)	—	110(a)	112
Included in other comprehensive income	—	—	21(b)	21
Included in regulatory assets	—	—	(2)	(2)
Change in collateral	—	—	(22)	(22)
Purchases, sales, issuances and settlements				
Purchases	—	13	15	28
Sales	—	(1)	—	(1)
Transfers out of Level 3 — Liability	—	—	26	26
Balance as of September 30, 2010	$ —	$ 12	$ 104	$ 116
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, 2010	$ —	$ —	$ 112	$ 112

(a) Includes the reclassification of $4 million and $2 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, 2010, respectively.

(b) Excludes increases in fair value of $186 million and $386 million and realized losses reclassified from OCI due to settlements of $69 million and $230 million associated with Generation's financial swap contract with ComEd for the three and nine months ended September 30, 2010, respectively. The PECO block contracts were designated as normal sales as of May 31, 2010. As such, there were no effective changes in the fair value of the block contracts with PECO for the three months ended September 30, 2010, as the mark-to-market balances previously recorded will be amortized over the term of the contract. The increase in fair value was $3 million through May 31, 2010. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

(c) The servicing liability related to PECO's accounts receivable agreement was released in accordance with new guidance on accounting for transfers of financial assets that was adopted on January 1, 2010. See Note 7 — Debt and Credit Agreements for additional information.

(d) Includes purchases of $2 million at September 30, 2010 related to pledged assets for Zion Station decommissioning.

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

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The following tables present total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2011 and 2010:

	Operating Revenue	Purchased Power	Fuel	Other, net
Total gains (losses) included in income for the three months ended September 30, 2011	$ (5)	$ (6)	$ 3	$ —
Total gains (losses) included in income for the nine months ended September 30, 2011	$ 2	$ (3)	$ 1	$ —
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2011	$ 1	$ (9)	$ 3	$ —
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2011	$ 22	$ (7)	$ 3	$ —

	Operating Revenue	Purchased Power	Fuel	Other, net
Total gains (losses) included in income for the three months ended September 30, 2010	$ (6)	$ 26	$10	$ —
Total gains included in income for the nine months ended September 30, 2010	$ 7	$ 62	$41	$ 2
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2010	$ (1)	$ 24	$11	$ —
Change in the unrealized gains relating to assets and liabilities for the three months ended September 30, 2010	$ 22	$ 57	$33	$ —

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, 2011 and December 31, 2010:

As of September 30, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 115	$ —	$ —	$ 115
Nuclear decommissioning trust fund investments				
Cash equivalents	320	20	—	340
Equity securities(b)	1,147	—	—	1,147
Commingled funds(c)	—	1,791	—	1,791
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	598	91	—	689
Debt securities issued by states of the United States and political subdivisions of the states	—	549	—	549
Corporate debt securities	—	701	—	701
Federal agency mortgage-backed securities	—	901	—	901
Commercial mortgage-backed securities (non-agency)	—	116	—	116
Residential mortgage-backed securities (non-agency)	—	5	—	5
Other debt obligations	—	64	6	70
Nuclear decommissioning trust fund investments subtotal(d)	2,065	4,238	6	6,309
Pledged assets for Zion Station decommissioning				
Equity securities	43	—	—	43
Commingled funds(c)	—	67	—	67
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	114	22	—	136
Debt securities issued by states of the United States and political subdivisions of the states	—	49	—	49
Corporate debt securities	—	291	—	291
Federal agency mortgage-backed securities	—	123	—	123
Commercial mortgage-backed securities (non-agency)	—	12	—	12
Private equity	—	—	38	38
Other debt obligations	—	2	—	2
Pledged assets for Zion Station decommissioning subtotal(e)	157	566	38	761
Rabbi trust investments(f)(g)	4	—	—	4
Mark-to-market derivative assets				
Cash flow hedges	—	413	664	1,077
Other derivatives	—	1,194	15	1,209
Proprietary trading	—	165	52	217
Effect of netting and allocation of collateral(h)	(1)	(1,058)	(17)	(1,076)
Mark-to-market assets(i)	(1)	714	714	1,427
Total assets	2,340	5,518	758	8,616
Liabilities				
Mark-to-market derivative liabilities				
Cash flow hedges(j)	—	(141)	—	(141)
Other derivatives	(1)	(651)	(16)	(668)
Proprietary trading	—	(161)	(26)	(187)
Effect of netting and allocation of collateral(h)	1	910	18	929
Mark-to-market liabilities	—	(43)	(24)	(67)
Deferred compensation	—	(17)	—	(17)
Total liabilities	—	(60)	(24)	(84)
Total net assets	$ 2,340	$ 5,458	$ 734	$ 8,532

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

As of December 31, 2010	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 419	$ —	$ —	$ 419
Nuclear decommissioning trust fund investments				
Cash equivalents	1	—	—	1
Equity securities(b)	1,513	—	—	1,513
Commingled funds(c)	—	2,212	—	2,212
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	504	96	—	600
Debt securities issued by states of the United States and political subdivisions of the states	—	451	—	451
Corporate debt securities	—	619	—	619
Federal agency mortgage-backed securities	—	804	—	804
Commercial mortgage-backed securities (non-agency)	—	114	—	114
Residential mortgage-backed securities (non-agency)	—	14	—	14
Other debt obligations	—	48	—	48
Nuclear decommissioning trust fund investments subtotal(d)	2,018	4,358	—	6,376
Pledged assets for Zion Station decommissioning				
Equity securities	84	—	—	84
Commingled funds(c)	—	132	—	132
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	166	12	—	178
Debt securities issued by states of the United States and political subdivisions of the states	—	45	—	45
Corporate debt securities	—	263	—	263
Federal agency mortgage-backed securities	—	102	—	102
Commercial mortgage-backed securities (non-agency)	—	14	—	14
Other debt obligations	—	2	—	2
Pledged assets for Zion Station decommissioning subtotal(e)	250	570	—	820
Rabbi trust investments(f)(g)	4	—	—	4
Mark-to-market derivative assets				
Cash flow hedges	—	724	992	1,716
Other derivatives	2	1,695	53	1,750
Proprietary trading	—	235	46	281
Effect of netting and allocation of collateral(h)	(3)	(1,848)	(38)	(1,889)
Mark-to-market assets(i)	(1)	806	1,053	1,858
Total assets	2,690	5,734	1,053	9,477
Liabilities				
Mark-to-market derivative liabilities				
Cash flow hedges	—	(45)	—	(45)
Other derivatives	(2)	(667)	(25)	(694)
Proprietary trading	—	(233)	(21)	(254)
Effect of netting and allocation of collateral(h)	1	914	23	938
Mark-to-market liabilities	(1)	(31)	(23)	(55)
Deferred compensation	—	(20)	—	(20)
Total liabilities	(1)	(51)	(23)	(75)
Total net assets	$ 2,689	$ 5,683	$ 1,030	$ 9,402

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

(b) Generation's NDT funds hold equity portfolios whose performance is benchmarked against established indices.

(c) Generation's NDT funds and Zion Station decommissioning pledged assets own commingled funds that invest in equity securities. Generation's NDT funds and Zion Station decommissioning pledged assets also own commingled funds that invest in fixed income securities. The commingled funds seek to out-perform certain established indices.

(d) Excludes net (liabilities) assets of $(83) million and $32 million at September 30, 2011 and December 31, 2010, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

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

(e) Excludes net assets of $2 million and $4 million at September 30, 2011 and December 31, 2010, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(f) The mutual funds held by the Rabbi trusts that are invested in common stock of Standard and Poor's 500 companies and Pennsylvania municipal bonds are primarily rated as investment grade.
(g) Excludes $6 million and $7 million of the cash surrender value of life insurance investments at September 30, 2011 and December 31, 2010, respectively.
(h) Includes collateral postings received from counterparties. Collateral received from counterparties, net of collateral (paid) to counterparties, totaled $148 million and $(1) million allocated to Level 2 and Level 3 mark-to-market derivatives, respectively, as of September 30, 2011. Collateral received from counterparties, net of collateral (paid) to counterparties, totaled $2 million, $934 million and $15 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2010.
(i) The Level 3 balance includes current and noncurrent assets for Generation of $415 million and $247 million at September 30, 2011 and $450 million and $525 million at December 31, 2010, respectively, related to the fair value of Generation's financial swap contract with ComEd; and current assets of $2 million and $5 million at September 30, 2011 and December 31, 2010, respectively, related to the fair value of Generation's block contracts with PECO. All of the mark-to-market balances Generation carries associated with the financial swap contract with ComEd and the block contracts with PECO eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(j) Excludes $13 million mark-to-market liability relating to an interest rate swap in connection with the DOE loan guarantee financing for Antelope Valley discussed in Note 6 – Derivative Financial Instruments. The fair value of the swap would be considered a Level 2 liability.

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, 2011 and September 30, 2010:

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)
Change 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 gains 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)
Change in collateral	—	—	15	15
Purchases, sales, issuances and settlements				
Purchases	6	60	4	70
Sales	—	(22)	—	(22)
Transfers out of Level 3 — Asset	—	—	(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 and 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 nine months ended September 30, 2011 . All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

Three Months Ended September 30, 2010	Nuclear Decommissioning Trust Fund Investments (c)	Mark-to-Market Derivatives	Total
Balance as of June 30, 2010	$ 1	$ 1,086	$1,087
Total realized / unrealized losses			
Included in income	—	30(a)	30
Included in other comprehensive income	—	131(b)	131
Changes in collateral	—	(14)	(14)
Purchases, sales, issuances and settlements			
Purchases	12	4	16
Sales	(1)	—	(1)
Transfers out of Level 3 — Liability	—	3	3
Balance as of September 30, 2010	$ 12	$ 1,240	$1,252
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of September 30, 2010	$ —	$ 34	$ 34

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

Nine Months Ended September 30, 2010	Nuclear Decommissioning Trust Fund Investments(c)	Mark-to-Market Derivatives	Total
Balance as of December 31, 2009	$ —	$ 931	$ 931
Total realized / unrealized gains			
Included in income	—	110(a)	110
Included in other comprehensive income	—	180(b)	180
Changes in collateral	—	(22)	(22)
Purchases, sales, issuances and settlements			
Purchases	13	15	28
Sales	(1)	—	(1)
Transfers out of Level 3 — Liability	—	26	26
Balance as of September 30, 2010	$ 12	$ 1,240	$1,252
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of September 30, 2010	$ —	$ 112	$ 112

(a) Includes the reclassification of $4 million and $2 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, 2010, respectively.
(b) Includes increases in fair value of $186 million and $386 million and realized losses reclassified from OCI due to settlements of $69 million and $230 million associated with Generation's financial swap contract with ComEd for the three and nine months ended September 30, 2010, respectively. 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, 2010, as the mark-to-market balances previously recorded will be amortized over the term of the contract. The increase in fair value was $3 million through May 31, 2010. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(c) Includes purchases of $2 million at September 30, 2010 related to pledged assets for Zion Station decommissioning.

The following tables present total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2011 and 2010:

	Operating Revenue	Purchased Power	Fuel
Total gains (losses) included in income for the three months ended September 30, 2011	$ (5)	$ (6)	$ 3
Total gains (losses) included in income for the nine months ended September 30, 2011	$ 2	$ (3)	$ 1
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2011	$ 1	$ (9)	$ 3
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2011	$ 22	$ (7)	$ 3

	Operating Revenue	Purchased Power	Fuel
Total gains (losses) included in income for the three months ended September 30, 2010	$ (6)	$ 26	$10
Total gains included in income for the nine months ended September 30, 2010	$ 7	$ 62	$41
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2010	$ (1)	$ 24	$11
Change in the unrealized gains relating to assets and liabilities held for the nine months ended September 30, 2010	$ 22	$ 57	$33

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

ComEd

The following tables present assets and liabilities measured and recorded at fair value on ComEd's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of September 30, 2011 and December 31, 2010:

As of September 30, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 830	$ —	$ —	$ 830
Rabbi trust investments				
Mutual funds	21	—	—	21
Total assets	851	—	—	851
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark-to-market derivative liabilities(b)(c)	—	—	(712)	(712)
Total liabilities	—	(8)	(712)	(720)
Total net assets (liabilities)	$ 851	$ (8)	$(712)	$ 131

As of December 31, 2010	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 1	$ —	$ —	$ 1
Rabbi trust investments				
Mutual funds	23	—	—	23
Rabbi trust investment subtotal	23	—	—	23
Mark-to-market derivative assets	—	—	4	4
Total assets	24	—	4	28
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark-to-market derivative liabilities(b)	—	—	(975)	(975)
Total liabilities	—	(8)	(975)	(983)
Total net assets (liabilities)	$ 24	$ (8)	$(971)	$(955)

(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 $415 million and $247 million at September 30, 2011, respectively, and $450 million and $525 million at December 31, 2010, 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 $2 million and $48 million at September 30, 2011, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers. The current liability is included in other current liabilities in ComEd's Consolidated Balance Sheets.

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 September 30, 2011 and 2010:

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 the fair value of floating-to-fixed energy swap contracts with unaffiliated suppliers for the three and nine months ended September 30, 2011, respectively.

Three Months Ended September 30, 2010	Mark-to-Market Derivatives
Balance as of June 30, 2010	$ (1,010)
Total realized / unrealized gains included in regulatory assets(a)	(117)
Balance as of September 30, 2010	$ (1,127)

Nine Months Ended September 30, 2010	Mark-to-Market Derivatives
Balance as of December 31, 2009	$ (971)
Total realized / unrealized losses included in regulatory assets(a)	(156)
Balance as of September 30, 2010	$ (1,127)

(a) Includes decreases in fair value of $186 million and $386 million and realized gains due to settlements of $69 million and $230 million associated with ComEd's financial swap contract with Generation for the three and nine months ended September 30, 2010, respectively. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

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, 2011 and December 31, 2010:

As of September 30, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 494	$ —	$ —	$494
Rabbi trust investments — mutual funds(b)(c)	8	—	—	8
Total assets	502	—	—	502
Liabilities				
Deferred compensation obligation	—	(21)	—	(21)
Mark-to-market derivative liabilities(d)	—	—	(3)	(3)
Total liabilities	—	(21)	(3)	(24)
Total net assets (liabilities)	$ 502	$ (21)	$ (3)	$478

As of December 31, 2010	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 499	$ —	$ —	$499
Rabbi trust investments — mutual funds(b)(c)	7	—	—	7
Total assets	506	—	—	506
Liabilities				
Deferred compensation obligation	—	(23)	—	(23)
Mark-to-market derivative liabilities(d)	—	—	(9)	(9)
Total liabilities	—	(23)	(9)	(32)
Total net assets (liabilities)	$ 506	$ (23)	$ (9)	$474

(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 invest in common stock of Standard and Poor's 500 companies and Pennsylvania municipal bonds that are primarily rated as investment grade.
(c) Excludes $13 million of the cash surrender value of life insurance investments at September 30, 2011 and December 31, 2010.
(d) The Level 3 balances include current liabilities of $2 million and $5 million at September 30, 2011 and December 31, 2010, respectively, related to the fair value of PECO's block contracts with Generation that eliminate 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, 2011 and 2010:

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)

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

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 eliminates upon consolidation in Exelon's Consolidated Financial Statements.

There were no changes in fair value for mark-to-market derivatives during the three months ended September 30, 2010.

Nine Months Ended September 30, 2010	Mark-to-Market Derivatives	Servicing Liability	Total
Balance as of December 31, 2009	$ (4)	$ (2)	$ (6)
Total realized / unrealized gains (losses)			
Included in net income	—	2(a)	2
Included in regulatory assets	(5)(b)	—	(5)
Balance as of September 30, 2010	$ (9)	$ —	$ (9)

(a) The servicing liability related to PECO's accounts receivable agreement was released in accordance with new guidance on accounting for transfers of financial assets that was adopted on January 1, 2010. See Note — 7 Debt and Credit Agreements for additional information.
(b) Includes a decrease in fair value of $3 million associated with PECO's block contract with Generation, for the nine months ended September 30, 2010, which eliminates upon consolidation in Exelon's Consolidated Financial Statements.

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 and PECO). 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 Exelon's and 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 restrict the trust funds from holding alternative investments and limit the trust funds' exposures to investments in highly illiquid markets. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities, are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

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

Commingled funds, which are similar to mutual funds, are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair values of short-term commingled 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 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 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 9 — Nuclear Decommissioning for further discussion on the NDT fund investments.

Rabbi Trust Investments (Exelon, Generation, ComEd and PECO). 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 fair values of the shares of the funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

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 are valued 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. 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. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 1, 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. 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 beginning of the month 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 in and out of Level 2 and Level 3 generally occur when the contract tenure becomes more observable.

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 uses a calculation of future cash inflows and estimated future outflows related to the swap agreements, which are discounted based on current forward curves and netted to determine the current fair value. Additional inputs to the present value calculation may include the contract terms, counterparty credit risk and market parameters such as interest rates and volatility. 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 6 — Derivative Financial Instruments for further discussion on mark-to-market derivatives.

Deferred Compensation Obligations (Exelon, Generation, ComEd and PECO). 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.

Servicing Liability (Exelon and PECO). PECO is party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in customer accounts receivables designated under the agreement in exchange for proceeds of $225 million, which PECO accounted for as a sale under previous guidance on accounting for transfers of financial assets. A servicing liability was recorded for the agreement in accordance with the applicable authoritative guidance for servicing of financial assets. The servicing liability was included in other current liabilities in Exelon's and PECO's Consolidated Balance Sheets. The fair value of the liability was determined using internal estimates based on provisions in the agreement, which were categorized as Level 3 inputs in the fair value hierarchy. The servicing liability was released in accordance with guidance on accounting for transfers of financial assets that was adopted on January 1, 2010.

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

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. 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. Exposure to interest rate risk exists as a result of the issuance of variable and fixed-rate debt, commercial paper and lines of credit.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value. Under these provisions, economic hedges are recognized on the balance sheet at their fair value unless they qualify for the normal purchases and normal sales exception. The Registrants have applied the normal purchases and normal sales scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. For economic 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 transaction occurs. For economic hedges that do not qualify or are not designated as cash flow hedges, changes in the fair value of the derivative are recognized in earnings each period and are classified as other derivatives in the following tables. Non-derivative contracts for access to additional generation and for sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 18 of the 2010 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.

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

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 financial transmission rights, 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 risk on a ratable basis over three-year periods. As of September 30, 2011, the percentage of expected generation hedged was 97%-100%, 85%-88%, and 56%-59% for the remainder of 2011, 2012 and 2013, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include cash flow hedges, other derivatives and certain non-derivative contracts including sales to ComEd and PECO 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 agreements, which are further discussed in Note 2 of the 2010 Form 10-K, qualify for the normal purchases and normal sales scope 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 has been designated by Generation as a cash flow hedge. Consequently, Generation records the fair value of the swap on its balance sheet and records changes in fair value to OCI. ComEd has not elected hedge accounting for this derivative financial instrument. ComEd records the fair value of the swap on its balance sheet, however, since the financial swap contract was deemed prudent by the Illinois Settlement Legislation, ComEd receives full cost recovery for the contract in rates and the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 2 of the 2010 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 begins 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 3 — 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 are being amortized over the terms of the contracts, which began on January 1, 2011.

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

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 qualify for the normal purchases and normal sales scope exception and have been designated as such. Additionally, in accordance with the 2010 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 2010 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 covers 22% to 29% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into purely to profit from market price changes as opposed to hedging an exposure and is subject to limits established by Exelon's RMC. The proprietary trading activities, which included volumes of 1,679 GWh and 4,508 GWh for the three and nine months ended September 30, 2011, respectively, and 1,077 GWh and 2,885 GWh for the three and nine months ended September 30, 2010, respectively, are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's revenue from energy marketing activities. Neither ComEd nor PECO enter into derivatives for proprietary trading purposes.

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

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. A hypothetical 10% increase in the interest rates associated with variable-rate debt would result in less than a $1 million decrease in each of Exelon's, ComEd's and PECO's pre-tax income for the three months ended September 30, 2011.

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		Gain (Loss) on Borrowings	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
Income Statement Classification	2011	2010	2011	2010
Interest expense	$ 1	$ 7	$ (1)	$ (7)

At September 30, 2011 and December 31, 2010, Exelon had $100 million of notional amounts of fair value hedges outstanding related to interest rate swaps, with fair value assets of $15 million and $14 million, respectively, which expire in 2015. During the three and nine months ended September 30, 2011 and 2010, there was no impact on the results of operations as a result of ineffectiveness from fair value hedges.

Cash Flow Hedges. In connection with the DOE guaranteed loan for the Antelope Valley acquisition, as discussed in Note 7 — Debt and Credit Agreements, Generation entered into a floating-to-fixed interest rate swap with a notional amount of $485 million, which hedges approximately 75% of Generation's future interest rate exposure associated with the financing. The swap 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 through the remaining term of the hedge. In order to mitigate this earnings impact, a series of offsetting hedge transactions will be executed as Generation draws on the loan.

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

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 normal purchases and normal sales 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, 2011:

	Generation					ComEd	PECO	Other		Exelon
Derivatives	Cash Flow Hedges (a)(d)	Other Derivatives	Proprietary Trading	Collateral and Netting (b)	Subtotal (c)	Other Derivatives (a)(e)	Other Derivatives (d)	Other Derivatives	Intercompany Eliminations (a)(d)	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 287	$ 814	$ 164	$ (787)	$ 478	$ —	$ —	$ —	$ —	$ 478
Mark-to-market derivative assets with affiliate (current assets)	417	—	—	—	417	—	—	—	(417)	—
Mark-to-market derivative assets (noncurrent assets)	126	395	53	(289)	285	—	—	15	—	300
Mark-to-market derivative assets with affiliate (noncurrent assets)	247	—	—	—	247	—	—	—	(247)	—
Total mark-to-market derivative assets	$ 1,077	$ 1,209	$ 217	$ (1,076)	$ 1,427	$ —	$ —	$ 15	$ (664)	$ 778
Mark-to-market derivative liabilities (current liabilities)	$ (64)	$ (514)	$ (141)	$ 670	$ (49)	$ (2)	$ (1)	$ —	$ —	$ (52)
Mark-to-market derivative liability with affiliate (current liabilities)	—	—	—	—	—	(415)	(2)	—	417	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(77)	(154)	(46)	259	(18)	(48)	—	—	—	(66)
Mark-to-market derivative liability with affiliate (noncurrent liabilities)	—	—	—	—	—	(247)	—	—	247	—
Total mark-to-market derivative liabilities	(141)	(668)	(187)	929	(67)	(712)	(3)	—	664	(118)
Total mark-to-market derivative net assets (liabilities)	$ 936	$ 541	$ 30	$ (147)	$ 1,360	$ (712)	$ (3)	$ 15	$ —	$ 660

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $415 million and $247 million, respectively, related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above. Excludes $13 million noncurrent liability relating to an interest rate swap in connection with a loan agreement to fund Antelope Valley 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 $113 million and $28 million, respectively, and current and noncurrent liabilities are shown inclusive of collateral of $4 million and $2 million, respectively. The total cash collateral received, net of cash collateral posted and offset against mark-to-market assets and liabilities was $147 million at September 30, 2011.

(d) Includes current assets for Generation and current liabilities for PECO of $2 million related to the fair value of PECO's block contracts with Generation. There were no netting adjustments or collateral received as of September 30, 2011. The PECO block contracts were designated as normal purchases in May 2010. As such, no additional changes in fair value of PECO's block contracts were recorded and the mark-to-market balances previously recorded are being amortized over the terms of the contracts.

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

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The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2010:

	Generation					ComEd	PECO	Other		Exelon
Derivatives	Cash Flow Hedges (a)(d)	Other Derivatives	Proprietary Trading	Collateral and Netting (b)	Subtotal (c)	Other Derivatives (a)(e)	Other Derivatives (d)	Other Derivatives	Intercompany Eliminations (a)(d)	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 532	$ 1,203	$ 225	$ (1,473)	$ 487	$ —	$ —	$ —	$ —	$ 487
Mark-to-market derivative assets with affiliate (current assets)	455	—	—	—	455	—	—	—	(455)	—
Mark-to-market derivative assets (noncurrent assets)	204	547	56	(416)	391	4	—	14	—	409
Mark-to-market derivative assets with affiliate (noncurrent assets)	525	—	—	—	525	—	—	—	(525)	—
Total mark-to-market derivative assets	$ 1,716	$ 1,750	$ 281	$ (1,889)	$ 1,858	$ 4	$ —	$ 14	$ (980)	$ 896
Mark-to-market derivative liabilities (current liabilities)	$ (21)	$ (551)	$ (200)	$ 738	$ (34)	$ —	$ (4)	$ —	$ —	$ (38)
Mark-to-market derivative liability with affiliate (current liabilities)	—	—	—	—	—	(450)	(5)	—	455	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(24)	(143)	(54)	200	(21)	—	—	—	—	(21)
Mark-to-market derivative liability with affiliate (noncurrent liabilities)	—	—	—	—	—	(525)	—	—	525	—
Total mark-to-market derivative liabilities	(45)	(694)	(254)	938	(55)	(975)	(9)	—	980	(59)
Total mark-to-market derivative net assets (liabilities)	$ 1,671	$ 1,056	$ 27	$ (951)	$ 1,803	$ (971)	$ (9)	$ 14	$ —	$ 837

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $450 million and $525 million, respectively, 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 $725 million and $199 million, respectively, and current and noncurrent liabilities are shown inclusive of collateral of $10 million and million $17 million, respectively. The total cash collateral received net of cash collateral posted and offset against mark-to-market assets and liabilities was $951 million at September 30, 2010.
(d) Includes current assets for Generation and current liabilities for PECO of $5 million related to the fair value of PECO's block contracts with Generation. There were no netting adjustments or collateral received as of December 31, 2010. The PECO block contracts were designated as normal purchases in May 2010. As such, no additional changes in the fair value of PECO's block contracts were recorded. Previously recorded mark-to-market balances are being amortized over the terms of the contracts.
(e) Includes noncurrent assets related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Cash Flow Hedges (Exelon, Generation and ComEd). Economic hedges that qualify as cash flow hedges primarily consist of forward power sales and power swaps on base load generation. At September 30, 2011, Generation had net unrealized pre-tax gains on effective cash flow hedges of $ 944 million being deferred within accumulated OCI, including $662 million related to the financial swap with ComEd. Amounts recorded in accumulated OCI related to changes in energy commodity cash flow hedges are reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs. Reclassifications from OCI are included in operating revenues, purchased power and fuel in Exelon's and

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

Generation's Consolidated Statements of Operations, depending on the commodities involved in the hedged transaction. Based on market prices at September 30, 2011, approximately $645 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 $415 million related to the financial swap with ComEd. However, the actual amount reclassified from accumulated OCI could vary due to future changes in market prices. Generation expects the settlement of the majority of its cash flow hedges, including the ComEd financial swap contract, will occur during 2011 through 2013.

Exelon discontinues hedge accounting prospectively when it determines that the derivative is no longer effective in offsetting changes in the cash flows of a hedged item or when it is no longer probable that the forecasted transaction will occur. For the three months ended September 30, 2011 and 2010, 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, 2011 and 2010, containing information about the changes in the fair value of cash flow hedges and the reclassification from accumulated OCI into results of operations. The amounts reclassified from accumulated OCI, when combined with the impacts of the actual physical power sales, result in the ultimate recognition of net revenues at the contracted price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended September 30, 2011	Income Statement Location	Energy-Related Hedges	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 Revenue	(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, and $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 $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 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 $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	Total Cash Flow Hedge OCI Activity, Net of Income Tax — 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 Revenue	(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 $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 $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 $ 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, respectively.

Three Months Ended September 30, 2010	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, 2010		$ 1,158(a)	$ 525
Effective portion of changes in fair value		401(b)	283(e)
Reclassifications from accumulated OCI to net income	Operating Revenue	(104)(c)	(59)(f)
Ineffective portion recognized in income	Purchased Power	(2)	(2)
Accumulated OCI derivative gain at September 30, 2010		$ 1,453(a)(d)	$ 747

(a) Includes $681 million and $610 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, and $3 million of gains, net of taxes, related to the fair value of the block contracts with PECO as of September 30, 2010 and June 30, 2010, respectively.
(b) Includes $113 million gain, net of taxes, related to the effective portion of changes in fair value of the five-year financial swap contract with ComEd for the three months ended September 30, 2010. 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, 2010 as the mark-to-market balances previously recorded will be amortized over the term of the contract.
(c) Includes $42 million loss, net of taxes, of reclassifications 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, 2010.
(d) Excludes $2 million gain, net of taxes, related to interest rate swaps.
(e) Includes $3 million of losses and $1 million of gains, net of taxes, related to the effective portion of changes in fair value of treasury rate locks at Generation and ComEd, respectively.

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

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(f) Reflects the reclassification of $4 million to regulatory assets and $1 million to deferred income tax liabilities within Exelon's and ComEd's Consolidated Balance Sheets associated with settled treasury rate locks at ComEd.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Nine Months Ended September 30, 2010	Income Statement Location	Energy-Related Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at December 31, 2009		$ 1,152(a)	$ 551
Effective portion of changes in fair value		736(b)	489(e)
Reclassifications from accumulated OCI to net income	Operating Revenue	(433)(c)	(291)(f)
Ineffective portion recognized in income	Purchased Power	(2)	(2)
Accumulated OCI derivative gain at September 30, 2010		$ 1,453(a)(d)	$ 747

(a) Includes $681 million and $585 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, and $3 million and $1 million of gains, net of taxes, related to the fair value of the block contracts with PECO as of September 30, 2010 and December 31, 2009, respectively.
(b) Includes $235 million gain, net of taxes, related to the effective portion of changes in fair value of the five-year financial swap contract with ComEd, and a $2 million of gains, net of taxes, of the effective portion of changes in fair value of the block contracts with PECO for the nine months ended September 30, 2010. During the second quarter of 2010 the block contracts with PECO were designated as normal sales. As such, the mark-to-market balance on Generation's Consolidated Balance Sheet will be amortized over the term of the contract.
(c) Includes a $139 million loss, net of taxes, of reclassifications from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd for the nine months ended September 30, 2010.
(d) Excludes $2 million of gains, net of taxes, related to interest rate swaps settled.
(e) Includes a $3 million of gains and $3 million of losses, net of taxes, related to the effective portion of changes in fair value of treasury rate locks at Generation and ComEd, respectively.
(f) Reflects the reclassification of $4 million to regulatory assets and $1 million to deferred income tax liabilities within Exelon's and ComEd's Consolidated Balance Sheets associated with settled treasury rate locks at ComEd.

During the three and nine months ended September 30, 2011, Generation's cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $162 million and a $617 million pre-tax gain, respectively, and a $171 million and $715 million pre-tax gain for the three and nine months ended September 30, 2010, respectively. Given that the cash flow hedges primarily consist of forward power sales and power swaps and do not include gas options or sales, the ineffectiveness of Generation's cash flow hedges is primarily the result of differences between the locational settlement prices of the cash flow hedges and the hedged generating units. This price difference is 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 decreases of $12 million and increases of $3 million for the three months ended September 30, 2011 and 2010, respectively, none of which was related to Generation's financial swap contract with ComEd or Generation's block contracts with PECO. During the nine months ended September 30, 2011 and 2010, cash flow hedge ineffectiveness decreased by $4 million and increased by $3 million, respectively, primarily due to changes in market prices during the period, none of which was related to Generation's financial swap contract with ComEd or Generation's block contracts with PECO. At September 30, 2011 and 2010, cash flow hedge ineffectiveness resulted in a decrease of $3 million and an increase of $3 million, respectively, related to accumulated OCI on the balance sheet in order to reflect the effective portions of derivative gains or losses.

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

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 $74 million and a $305 million pre-tax gain for the three and nine months ended September 30, 2011, respectively, and a $102 million and a $485 million pre-tax gain for the three and nine months ended September 30, 2010, respectively. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices, were decreases of $12 million and increases of $3 million pre-tax for the three months ended September 30, 2011 and 2010, respectively, and decreases of $4 million and increases of $3 million for the nine months ended September 30, 2011 and 2010, respectively. At September 30, 2011 and 2010, cash flow hedge ineffectiveness resulted in a decrease of $3 million and an increase of $3 million, respectively, related to accumulated OCI on the balance sheet in order to reflect the effective portions of derivative gains or losses.

Other Derivatives (Exelon and Generation). Other derivative contracts are those that do not qualify or are not designated for hedge accounting. These instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, and forward sales. For the three and nine months ended September 30, 2011 and 2010, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in fuel and purchased power expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Exelon and Generation		
Three Months Ended September 30, 2011	**Purchased Power**	**Fuel**	**Total**
Change in fair value	$ (8)	$ 30	$ 22
Reclassification to realized at settlement	(51)	(50)	(101)
Net mark-to-market (losses)	$ (59)	$ (20)	$ (79)

	Exelon and Generation		
Nine Months Ended September 30, 2011	**Purchased Power**	**Fuel**	**Total**
Change in fair value	$ (29)	$ 42	$ 13
Reclassification to realized at settlement	(227)	(145)	(372)
Net mark-to-market (losses)	$ (256)	$(103)	$(359)

	Exelon and Generation		
Three Months Ended September 30, 2010	**Purchased Power**	**Fuel**	**Total**
Change in fair value	$ 161	$ 55	$ 216
Reclassification to realized at settlement	(57)	1	(56)
Net mark-to-market gains	$ 104	$ 56	$ 160

	Exelon and Generation		
Nine Months Ended September 30, 2010	**Purchased Power**	**Fuel**	**Total**
Change in fair value	$ 343	$ 129	$ 472
Reclassification to realized at settlement	(204)	2	(202)
Net mark-to-market gains	$ 139	$ 131	$ 270

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

Proprietary Trading Activities (Exelon and Generation). For the three and nine months ended September 30, 2011 and 2010, 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,		Nine Months Ended September 30,	
		2011	2010	2011	2010
Change in fair value	Operating Revenue	$ 2	$ (1)	$ 22	$ 25
Reclassification to realized at settlement	Operating Revenue	(6)	(5)	(19)	(17)
Net mark-to-market gains (losses)	Operating Revenue	$ (4)	$ (6)	$ 3	$ 8

Credit Risk (Exelon, Generation, ComEd and PECO)

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.

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

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase and normal sales, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of September 30, 2011. 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 maturity of a company's credit risk by credit rating of the counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs, NYMEX and ICE 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 and PECO of $57 million and $38 million, respectively.

Rating as of September 30, 2011	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	$ 968	$ 167	$ 801	2	$ 192
Non-investment grade	10	3	7	—	—
No external ratings					
Internally rated — investment grade	35	7	28	—	—
Internally rated — non-investment grade	4	2	2	—	—
Total	$ 1,017	$ 179	$ 838	2	$ 192

Net Credit Exposure by Type of Counterparty	As of September 30, 2011
Financial institutions	$ 368
Investor-owned utilities, marketers and power producers	281
Energy cooperatives and municipalities	152
Other	37
Total	$ 838

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, 2011, 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 2010 Form 10-K for further information.

PECO's supplier master agreements that govern the terms of its DSP Program 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, 2011, PECO's net credit exposure to suppliers was immaterial.

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 3 — Regulatory Matters for further information.

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of September 30, 2011, PECO had credit exposure of $9 million under its natural gas supply and asset management agreements with investment grade suppliers.

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

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. 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. Generation also enters into commodity transactions on NYMEX and ICE. The NYMEX and ICE clearing houses act as the counterparty to each trade. Transactions on NYMEX and ICE must adhere to comprehensive collateral and margining requirements.

Generation's interest rate swap contain provisions that, in the event of a merger, require that Exelon's debt maintain an investment grade credit rating from Moody's or S&P. If Exelon's debt were to fall below investment grade, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity.

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 NYMEX and ICE that are fully collateralized) was $662 million and $742 million as of September 30, 2011 and December 31, 2010, respectively. As of September 30, 2011 and December 31, 2010, Generation had the contractual right of offset of $607 million and $717 million, respectively, related to derivative instruments that are assets with the same counterparty under master netting agreements, resulting in a net liability position of $55 million and $25 million, respectively. If Generation had been downgraded to the investment grade rating of BBB- and Baa3, or lost its investment grade credit rating, it would have had additional collateral obligations of approximately $184 million or $948 million, respectively, as of September 30, 2011 and approximately $57 million or $944 million, respectively, as of December 31, 2010 related to its financial instruments, including derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements and the application of collateral. See Note 18 of the 2010 Form 10-K for further information regarding the letters of credit supporting the cash collateral.

Generation entered into SFCs with certain utilities, including PECO, 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, 2011, ComEd held both cash and letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts. These amounts were not material. Beginning in June 2010, under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, beginning in December 2010, 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, 2011, 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 2010 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, 2011, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of September 30, 2011, PECO could have been required to post approximately $44 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.

Exelon's interest rate swaps contain provisions that, in the event of a merger, require that Exelon's debt maintain an investment grade credit rating from Moody's or S&P. If Exelon's debt were to fall below investment grade, 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, 2011, Exelon's interest rate swap was in an asset position, with a fair value of $15 million.

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

As of September 30, 2011 and December 31, 2010, $1 million of cash collateral received was not offset against net derivative positions, because it was not associated with energy-related derivatives.

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

Short-Term Borrowings

Exelon and ComEd 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.

On March 23, 2011, Exelon Corporate, Generation and PECO replaced their unsecured revolving credit facilities with new facilities with aggregate bank commitments of $500 million, $5.3 billion and $600 million, respectively. Under these facilities, Exelon, Generation and PECO may issue letters of credit in the aggregate amount of up to $200 million, $3.5 billion and $300 million, respectively. The credit facilities expire on March 23, 2016, unless extended in accordance with the terms of the agreements. Each credit facility permits the applicable borrower to request two one-year extensions. Each credit facility also allows Exelon, Generation and PECO to request increases in the aggregate commitments up to an additional $250 million, in the case of each of Exelon and PECO, and up to an additional $1 billion in the case of Generation. Any such extensions or increases are subject to the approval of the lenders party to the credit facilities in their sole discretion. Exelon Corporate, Generation and PECO incurred $3 million, $37 million and $4 million, respectively, in costs related to the replacement of their credit facilities. These costs included upfront and arranger fees, as well as other costs such as external legal fees and filing costs. These costs will be amortized to interest expense over the terms of the credit facilities.

As of September 30, 2011, ComEd had access to an unsecured revolving credit facility with aggregate bank commitments of $1 billion that expires on March 25, 2013, unless extended in accordance with its terms. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $1 billion. ComEd may request two additional one-year extensions. In addition, ComEd may request increases in the aggregate bank commitments under its credit facility up to an additional $500 million. Any such extensions or increases are subject to the approval of the lenders party to the credit facility in their sole discretion.

Borrowings under each credit agreement bear interest at a rate selected by the borrower based upon either the prime rate or at a fixed rate for a specified period based upon a LIBOR-based rate. The Exelon, Generation and PECO agreements provide for adders of up to 85 basis points for prime-based borrowings and up to 185 basis points for the LIBOR-based borrowings based upon the credit rating of the borrower. At September 30, 2011, Exelon, Generation and PECO adders were 30, 30 and 10 basis points, respectively, for prime based borrowings and 130, 130 and 110 basis points, respectively, for LIBOR-based borrowings. The ComEd agreement provides adders of up to 137.5 basis points for prime-based borrowings and up to 237.5 basis points for LIBOR-based borrowings to be added, based upon ComEd's credit rating. At September 30, 2011, ComEd's adder was 87.5 basis points for prime based borrowings and 187.5 basis points for LIBOR-based borrowings.

Generation, ComEd and PECO had $30 million, $32 million and $32 million, respectively, of additional credit facility agreements with minority and community banks located primarily within ComEd's and PECO's service territories. These facilities expired on October 21, 2011 and were solely utilized to issue letters of credit. As of September 30, 2011, letters of credit issued under these agreements totaled $25 million, $21 million and $20 million for Generation, ComEd and PECO, respectively.

On October 21, 2011, 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.

Additionally, on November 4, 2010, Generation entered into a bilateral credit facility, which provides for an aggregate commitment of up to $500 million. The effectiveness and full availability of the credit facility were subject to various conditions. On February 22, 2011, Generation satisfied all conditions to the effectiveness and availability of credit under the credit facility for loans and letters of credit in the aggregate maximum amount of $300 million, which is the limit currently authorized by the board of directors of Exelon Corporation for this credit facility. Availability under the bilateral credit facility extends through December 2015 for $150 million of the $300 million commitment and March 2016 for the remaining $150 million. The bilateral credit facility will be used by Generation primarily to meet requirements for letters of credit but also permits cash borrowings at a rate of LIBOR or a base rate, plus an adder of 200 basis points. No cash borrowings are anticipated under the credit facility. In addition, Generation will pay a facility fee, payable on the first day of each calendar quarter at a rate per annum equal to a specified facility fee rate on the total amount of the credit facility regardless of usage.

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

Exelon, Generation, ComEd and PECO had the following amounts of commercial paper borrowings outstanding at September 30, 2011 and December 31, 2010:

Commercial Paper Borrowings	September 30, 2011	December 31, 2010
Exelon Corporate	$ 389	$ —
Generation	73(a)	—
ComEd	—	—
PECO	—	—

(a) Generation's commercial paper balance is included within short-term borrowings on the Generation Consolidated Balance Sheets.

As of September 30, 2011, there were no borrowings under the Registrants' credit facilities.

Issuance of Long-Term Debt

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 the January 2011 contribution to 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 and for general corporate purposes.
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 and for general corporate purposes.

(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.

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

During the nine months ended September 30, 2010, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount(a)	Use of Proceeds
Generation	Senior Notes	4.00%	October 1, 2020	$ 550	Used to finance the acquisition of John Deere Renewables and for general corporate purposes.
Generation	Senior Notes	5.75%	October 1, 2041	350	Used to finance the acquisition of John Deere Renewables and for general corporate purposes.
ComEd	First Mortgage Bonds	4.00%	August 1, 2020	500	Used to refinance First Mortgage Bonds, Series 102, which matured on August 15, 2010 and for other general corporate purposes.

(a) Excludes unamortized bond discounts of $1 million on Generation's senior notes due 2020 and 2041, respectively.

Retirement of Long-Term Debt

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

On October 12, 2011, ComEd retired $91 million of variable rate tax-exempt bonds due March 1, 2017, $50 million of variable rate tax-exempt bonds due March 1, 2020 and $50 million of variable rate tax exempt bonds due May 1, 2021.

During the nine months ended September 30, 2010, the following long-term debt was retired:

Company	Type	Interest Rate	Maturity	Amount
Exelon	2005 Senior Notes	4.45%	June 15, 2010	$ 400
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	1
Generation	Montgomery County Series 1994 B Tax-Exempt Bonds	Variable	June 1, 2029	13
Generation	Indiana County Series 2003 A Tax-Exempt Bonds	Variable	June 1, 2027	17
Generation	York County Series 1993 A Tax-Exempt Bonds	Variable	August 1, 2016	19
Generation	Salem County 1993 Series A Tax-Exempt Bonds	Variable	March 1, 2025	23
Generation	Delaware County 1993 Series A Tax-Exempt Bonds	Variable	August 1, 2016	24
Generation	Montgomery County Series 1996 A Tax-Exempt Bonds	Variable	March 1, 2034	34
Generation	Montgomery County Series 1994 A Tax-Exempt Bonds	Variable	June 1, 2029	83
ComEd	Sinking fund debentures	4.75%	December 1, 2011	1
ComEd	First Mortgage Bonds	4.74%	August 15, 2010	212
PECO	PETT Transition Bonds	6.52%	September 1, 2010	806

Variable Rate Debt

As of September 30, 2011, ComEd's variable rate tax-exempt debt was supported by letters of credit, which were released and cancelled following the retirement of that debt in October 2011 as discussed above. ComEd has classified amounts outstanding under these debt agreements as short-term debt based on the retirement of the debt in October 2011.

Accounts Receivable Agreement

PECO is party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its customer accounts receivable designated under the agreement in exchange for proceeds of $225 million, which is classified as a short-term note payable on Exelon's and PECO's Consolidated Balance Sheets. As of September 30, 2011 and December 31, 2010, the financial institution's undivided interest in Exelon's and PECO's customer accounts receivable was equivalent to $351 million and $346 million, respectively, which is calculated under the terms of the agreement. Upon termination or liquidation of this agreement, the financial institution is entitled to recover up to $225 million plus the accrued yield payable from its undivided interest in PECO's receivables. On September 2, 2011, PECO extended this agreement, which now terminates on August 31, 2012. As of September 30, 2011, PECO was in compliance with the requirements of the agreement. In the event the agreement is not further extended, PECO has sufficient short-term liquidity and may seek alternate financing.

Antelope Valley Project Development Debt Agreement

The DOE Loan Programs Office issued a guarantee for up to $646 million for a non-recourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. Advances under the loan are contingent on the satisfaction of various conditions. The purchase agreement contains a provision that First Solar, Inc. will repurchase Antelope Valley if initial funding of the loan does not occur by the end of 2011. The project is expected to be completed at the end of 2013. The loan will mature on January 5, 2037. Interest rates on the loan will be fixed upon each advance at a spread of 37.5 basis points above U.S. Treasuries of comparable maturity. In connection with this agreement, Generation entered into a floating-for-fixed interest rate swap with a notional amount of $485 million to mitigate interest rate risk associated with the financing. See Note 6 — Derivative Financial Instruments for additional information on the interest rate swap. In addition, Generation has issued letters of credit to support its equity investment in the project. As of September 30, 2011, Generation had $6 million in letters of credit outstanding related to the project. Generation expects to issue additional letters of credit to support their equity investment in the project prior to the first loan advance to Antelope Valley. The letters of credit balance is expected to decline over time as scheduled equity contributions for the project are made.

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

8. Income Taxes (Exelon, Generation, ComEd and PECO)

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, 2011	Exelon	Generation	ComEd	PECO
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	4.8	5.5	0.8	2.9
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 Acts(a)	—	—	0.3	—
Amortization of investment tax credit	(0.3)	(0.2)	(0.5)	(0.3)
Plant basis differences	(3.2)	—	(0.7)	(23.8)
Production tax credits	(1.1)	(1.7)	—	—
Other	0.1	0.3	0.4	0.1
Effective income tax rate	29.8%	30.2%	35.3%	13.9%

For the Nine Months Ended September 30, 2011	Exelon	Generation	ComEd	PECO
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	4.1	4.9	3.4	(0.4)
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 Acts(a)	—	—	(1.5)	—
Amortization of investment tax credit	(0.3)	(0.2)	(0.4)	(0.3)
Plant basis differences	(1.0)	—	(0.4)	(6.8)
Production tax credits	(1.0)	(1.4)	—	—
Other	(0.3)	(0.9)	0.3	—
Effective income tax rate	35.4%	35.8%	36.4%	27.5%

For the Three Months Ended September 30, 2010	Exelon	Generation	ComEd	PECO
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	1.6	3.2	4.8	(5.8)
Qualified nuclear decommissioning trust fund income	4.1	5.4	—	—
Domestic production activities deduction	(1.4)	(1.7)	—	—
Tax exempt income	(0.1)	(0.1)	—	—
Amortization of investment tax credit	(0.2)	(0.1)	(0.4)	(0.4)
Plant basis differences	—	—	(0.1)	—
Other	0.5	—	0.2	0.6
Effective income tax rate	39.5%	41.7%	39.5%	29.4%

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

For the Nine Months Ended September 30, 2010	Exelon	Generation	ComEd	PECO
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	2.8	3.7	6.6	(5.9)
Qualified nuclear decommissioning trust fund income	1.3	1.7	—	—
Domestic production activities deduction	(1.8)	(2.4)	—	—
Tax exempt income	(0.1)	(0.2)	—	—
Health Care Reform Acts(b)	1.7	0.9	1.7	1.7
Amortization of investment tax credit	(0.2)	(0.2)	(0.4)	(0.4)
Plant basis differences	—	—	(0.1)	0.1
Uncertain tax position remeasurement	—	(2.6)	11.5	—
Other	0.1	—	0.2	0.2
Effective income tax rate	38.8%	35.9%	54.5%	30.7%

(a) Includes one-time income tax benefit at ComEd recorded pursuant to the 2010 Rate Case order for the recovery of costs related to the passage of the Health Care Reform Acts in 2010. See Note 3 — Regulatory Matters for additional information.
(b) See Note 10 — Retirement Benefits for further discussion regarding the impact of the Health Care Reform Acts on income tax expense.

Accounting for Uncertainty in Income Taxes

Exelon, Generation, ComEd and PECO have $836 million, $710 million, $70 million and $48 million, respectively, of unrecognized tax benefits as of September 30, 2011. Exelon's, Generation's, ComEd's and PECO's uncertain tax positions have not significantly changed since December 31, 2010. See Note 11 of the 2010 Form 10-K 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 second quarter of 2010, Exelon concluded that it had sufficient new information that a remeasurement of the involuntary conversion and CTC positions was required in accordance with applicable accounting standards. As a result, Exelon recorded $65 million (after-tax) of interest expense, of which $36 million (after-tax) and $22 million (after-tax) were recorded at ComEd and PECO, respectively. ComEd also recorded a current tax expense of $70 million offset with a tax benefit recorded at Generation of $70 million. In the third quarter of 2010, Exelon and IRS Appeals reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion and CTC positions. The agreement is consistent with IRS Appeals' second quarter 2010 offer to settle the involuntary conversion and CTC positions and also includes IRS Appeals' agreement to withdraw its assertion of the $110 million substantial understatement penalty with respect to Exelon's involuntary conversion position. Final resolution of the involuntary conversion and CTC disputes remains subject to finalizing terms and calculations and executing definitive agreements satisfactory to both parties. 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.

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, of which $405 million would be paid by ComEd, $135 million would be received by PECO, $10 million would be paid by Generation and the remainder received by 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. Further, Exelon expects to receive additional tax refunds of approximately $365 million between 2012 and 2014, including the refund resulting from the nuclear decommissioning trust fund special transfer tax deduction described below, of which $55 million and $335 million would be received by Generation and ComEd, respectively, and the remainder paid by Exelon.

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 the first half of 2012 after the final resolution of the involuntary conversion and CTC settlement. 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, 2011, assuming Exelon's preliminary 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 $850 million, of which $540 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, 2011, by as much as $250 million, net of tax, of which $190 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.

Nuclear Decommissioning Trust Fund Special Transfer Tax Deduction (Exelon and Generation)

During 2008, Generation benefited from a provision in the Energy Policy Act of 2005 which allowed companies an income tax deduction for a "special transfer" of funds from a non-tax qualified NDT fund to a qualified NDT fund. As a result of temporary guidance published by the U.S. Department of Treasury, Generation completed a special transfer in the first quarter of 2008 for tax year 2008. In December 2010, the U.S. Department of Treasury issued final regulations under IRC Section 468A. The final regulations included a transitional relief provision that allowed taxpayers to request permission from the IRS to designate a taxable year, as far back as 2006, during which the special transfer will be deemed to have occurred. Exelon determined, and confirmed with the IRS through the ruling process, that this provision allows a majority of Generation's 2008 special transfer deduction to be claimed in the 2006 tax year and the remaining portions claimed ratably in taxable years 2007 and 2008. On February 18, 2011, in order to preserve both the ability to designate the special transfer from 2008 to an earlier taxable year and the ability to complete future additional special transfers, Exelon filed ruling requests with the IRS. As of October 20, 2011, Exelon has received favorable rulings from the IRS on all of its ruling requests. Exelon recorded an interest and tax benefit of $43 million, net of tax including the impact on the manufacturer's deduction, in the second quarter of 2011 related to the special transfer completed in 2008. In addition, during the third quarter, Exelon completed additional special transfers resulting in an additional interest benefit of $3 million, net of tax.

2011 Illinois State Tax Rate Legislation (Exelon, Generation and ComEd)

The Taxpayer Accountability and Budget Stabilization Act, (SB 2505), enacted into law in Illinois on January 13, 2011, increases the corporate tax rate in Illinois from 7.3% to 9.5% for tax years 2011 — 2014, provides for a reduction in the rate from 9.5% to 7.75% for tax years 2015 — 2024 and further reduces the rate from 7.75% to 7.3% for tax years 2025 and thereafter. Pursuant to the rate change, Exelon reevaluated its deferred state income taxes during the first quarter of 2011. Illinois' corporate income tax rate changes resulted in a charge to state deferred taxes (net of Federal taxes) during the first quarter of 2011 of $7 million, $11 million and $4 million for Exelon, Generation and ComEd, respectively. Exelon's and ComEd's charge is net of a regulatory asset of $15 million.

In 2011, the income tax rate change is expected to increase Exelon's Illinois income tax provision (net of Federal taxes) by approximately $5 million, of which $11 million and $4 million of additional tax relates to Exelon Corporate and Generation, respectively, and a $10 million benefit for ComEd. The 2011 tax benefit at ComEd reflects the impact of a 2011 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010 and the electric transmission and distribution property repairs deduction discussed below.

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, such as the 2011 Illinois State Tax Rate Legislation discussed above. Due to the extent and nature of the operations conducted by Exelon and Generation in Illinois, Exelon and Generation reevaluated their long-term state tax apportionment for Illinois and all other states where they have state income tax obligations. The effect of revising the long-term state tax apportionment resulted in the recording of a deferred state tax charge during the first quarter of 2011 of $22 million and $11 million (net of Federal taxes) for Exelon and Generation, respectively.

Pennsylvania Bonus Depreciation (Exelon, Generation and PECO)

Pursuant to authoritative guidance issued by the Pennsylvania Department of Revenue on February 24, 2011, Exelon is permitted to deduct 100% bonus depreciation in Pennsylvania in the year that such depreciation is claimed and allowable for Federal purposes. For Federal purposes, qualifying property placed into service after September 8, 2010, and before January 1, 2012, is eligible for 100% bonus depreciation. During the first quarter of 2011, the bonus depreciation deduction resulted in a benefit of approximately $8 million, $2 million and $6 million associated with property placed in service in 2010 at Exelon, Generation and PECO, respectively.

Accounting for Electric Transmission and Distribution Property Repairs (Exelon, Generation, ComEd and PECO)

On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for repair costs associated with electric transmission and distribution property. ComEd intends to adopt the safe harbor in the Revenue Procedure for the 2011 tax year. PECO adopted the safe harbor for the 2010 tax year. For the three and nine months ended September 30, 2011, the adoption of the safe harbor resulted in a $26 million reduction to income tax expense at PECO, while Generation incurred additional income tax expense in the amount of $23 million due to a decrease in its manufacturer's deduction, which are reflected in the effective income tax rate reconciliation above in the plant basis differences and domestic production activities deduction lines, respectively. For Exelon, the adoption had a minimal effect on consolidated earnings. In addition, the adoption of the safe harbor will result in a cash tax benefit at Exelon, ComEd and PECO in the amount of approximately $300 million, $250 million and $95 million, respectively, partially offset by a cash tax detriment at Generation in the amount of $28 million.

See Note 3 — Regulatory Matters for discussion of the regulatory treatment prescribed in the 2010 electric distribution rate case settlement for PECO's cash tax benefit resulting from the application of the method change to years prior to 2010.

Tax Sharing Agreement (Exelon, Generation, ComEd and PECO)

Generation, ComEd and PECO are all party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit. During the third quarter of 2011, Generation and PECO recorded an allocation of Federal benefits from Exelon under the Tax Sharing Agreement of $30 million and $18 million, respectively.

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

9. 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.

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.

During the third quarter of 2010, Generation's ARO decreased by $205 million, primarily reflecting the ZionSolutions' assumption of decommissioning and other liabilities for Zion Station, offset in part by accretion and by increases for updates to estimated future cash flows across all of Generation's units. Changes in estimated future cash flows increased the ARO by $452 million, including approximately $200 million associated with the accelerated timing of the Zion Station decommissioning. The remainder of the increase is the result of cost study estimate updates and the change in timing of general decommissioning activities at select sites in Generation's nuclear fleet, including revisions to the timing and amount of SNF disposal; partially offset by the impacts of lower escalation rates. This change in the ARO resulted in an immaterial impact to Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income.

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets from December 31, 2010 to September 30, 2011:

	Exelon and Generation
Nuclear decommissioning ARO at December 31, 2010(a)	$ 3,276
Accretion expense	155
Net increase due to changes in estimated cash flows	176
Costs incurred to decommission retired plants	(3)
Nuclear decommissioning ARO at September 30, 2011(a)	$ 3,604

(a) Includes $5 million as the current portion of the ARO at September 30, 2011 and December 31, 2010, which is included in other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

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

Nuclear Decommissioning Trust Fund Investments

Generation will pay for its nuclear decommissioning obligations using trust funds that have been established for this purpose. At September 30, 2011 and December 31, 2010, Exelon and Generation had NDT fund investments totaling $6,226 million and $6,408 million, respectively. The following table provides unrealized gains (losses) on NDT funds for the three and nine months ended September 30, 2011 and 2010:

	Exelon and Generation			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net unrealized gains (losses) on decommissioning trust funds — Regulatory Agreement Units(a)	$ (363)	$ 324	$ (223)	$ 117
Non-Regulatory Agreement Units(b)(c)	(141)	107	(88)	48

(a) Net unrealized gains and (losses) related to Generation's NDT funds associated with Regulatory Agreement Units are included in regulatory liabilities on Exelon's Consolidated Balance Sheets and noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
(b) Excludes $4 million of net unrealized losses and $41 million of net unrealized gains related to the Zion Station pledged assets for the three and nine months ended September 30, 2011, respectively. Unrealized gains and losses related to Zion Station pledged assets are included in the payable for Zion Station decommissioning on Exelon and Generation's Consolidated Balance Sheets.
(c) Gains and (losses) related to Generation's NDT funds associated with Non-Regulatory Agreement Units are included within Other, net in Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income.

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

See Note 2 of the 2010 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 the 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 2010 Form 10-K for information regarding the specific treatment of assets, including NDT funds, and decommissioning liabilities transferred in the transaction. On July 14, 2011, three people filed a purported class action lawsuit in the United States District Court for the Northern District of Illinois naming ZionSolutions and Bank of New York Mellon as defendants and seeking, among other things, an accounting for use of NDT funds, an injunction against the use of NDT funds, the appointment of a trustee for the NDT funds, and the return of NDT funds to customers of ComEd to the extent legally entitled thereto. ZionSolutions and Bank of New York Mellon filed a motion to dismiss the complaint on September 13, 2011.

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 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 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 $64 million, which is included within the nuclear decommissioning ARO at September 30, 2011. Generation also has retained NDT assets to fund its obligation to maintain and transfer the SNF at Zion Station. As of September 30, 2011, the carrying value of the Zion Station pledged assets and the payable to Zion Solutions was approximately $763 million and $720 million, respectively. The payable excludes a liability recorded within 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 Generation's Consolidated Balance Sheets at September 30, 2011 and December 31, 2010 was $116 million and $127 million, respectively.

Securities Lending Program. Generation's NDT funds participate in a securities lending program with the trustees of the funds. Under the program, securities loaned to the trustees are required to be collateralized by cash, U.S. Government securities or irrevocable bank letters of credit. Initial collateral levels are no less than 102% and 105% of the market value of the borrowed securities for collateral denominated in U.S. and foreign currency, respectively. Subsequent collateral levels, which are adjusted daily, must be maintained at a level no less than 100% of the market value of borrowed securities. Cash collateral received may not be sold or re-pledged by the trustees unless the borrower defaults.

In 2008, Exelon decided to end its participation in this securities lending program and initiated a gradual withdrawal of the trusts' investments in order to minimize potential losses due to liquidity constraints in the market. Currently, the weighted average maturity of the securities within the collateral pools is approximately 18 months. The fair value of securities on loan was approximately $16 million and $51 million at September 30, 2011 and December 31, 2010, respectively. The fair value of cash and non-cash collateral received for these loaned securities was $15 million at September 30, 2011 and $51 million at December 31, 2010. A portion of the income generated through the investment of cash collateral is remitted to the borrowers, and the remainder is allocated between the trusts and the trustees in their capacity as security agents.

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 10, 2010, Generation notified the NRC that it had remediated the December 31, 2009 underfunded position of its Byron and Braidwood NDT funds with the establishment of approximately $44 million in parent guarantees in accordance with a plan submitted by Generation to the NRC on July 31, 2009. On May 26, 2010, the NRC notified Generation that while the previously established parent guarantees complied with Generation's remediation plan, additional parent guarantees may be required to meet the future value of the underfunded position. During the third quarter of 2010, Generation established approximately $175 million in additional parent guarantees.

On March 31, 2011, Generation, within its NRC-required biennial decommissioning funding assurance submission, notified the NRC that parent guarantees are no longer required as a result of the modest recovery in the financial markets, which has improved decommissioning funding levels for Byron and Braidwood. Generation cancelled these parent guarantees on August 6, 2011. As the future values of trust funds change due to market conditions, the NRC minimum funding status of Generation's units will change. In addition, if changes occur to the regulatory agreement with the PAPUC that currently allows amounts to be collected from PECO

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customers for decommissioning the former PECO nuclear plants, the NRC minimum funding status of those plants could change at subsequent NRC filing dates. See Note 12 of the 2010 Form 10-K for further information on NRC minimum funding requirements.

10. Retirement Benefits (Exelon, Generation, ComEd and PECO)

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

Defined Benefit Pension and Other Postretirement Benefits

During the first quarter of 2011, Exelon received an updated valuation of its pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2011. This valuation resulted in a decrease to the pension obligations of $6 million and a decrease to other postretirement obligations of $28 million. Additionally, accumulated other comprehensive loss decreased by approximately $39 million (after tax) and regulatory assets increased by $31 million.

The following tables present the components of Exelon's net periodic benefit costs for the three and nine months ended September 30, 2011 and 2010. The 2011 pension benefit cost is calculated using an expected long-term rate of return on plan assets of 8.00%. The 2011 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 7.08%. 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,	
	2011	2010	2011	2010
Service cost	$ 53	$ 47	$ 36	$ 31
Interest cost	162	164	52	53
Expected return on assets	(235)	(200)	(27)	(27)
Settlements	—	4	—	—
Amortization of:				
Transition obligation	—	—	2	3
Prior service cost (benefit)	4	4	(10)	(14)
Actuarial loss	83	64	16	18
Net periodic benefit cost	$ 67	$ 83	$ 69	$ 64

	Pension Benefits Nine Months Ended September 30,		Other Postretirement Benefits Nine Months Ended September 30,	
	2011	2010	2011	2010
Service cost	$ 159	$ 143	$ 107	$ 93
Interest cost	487	494	155	160
Expected return on assets	(704)	(600)	(83)	(81)
Settlements	—	4	—	—
Amortization of:				
Transition obligation	—	—	7	7
Prior service cost (benefit)	11	11	(29)	(42)
Actuarial loss	248	191	49	55
Net periodic benefit cost	$ 201	$ 243	$ 206	$ 192

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

The following amounts were included in capital additions and operating and maintenance expense during the three and nine months ended September 30, 2011 and 2010, for Generation's, ComEd's, PECO's and BSC's allocated portion of the pension and postretirement benefit plans:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Pension and Postretirement Benefit Costs	**2011**	**2010**	**2011**	**2010**
Generation	$ 64	$ 68	$187	$202
ComEd	53	55	160	161
PECO	8	11	24	35
BSC(a)	11	13	36	37

(a) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations.

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 contributed $2.1 billion to its qualified pension plans in January 2011, representing substantially all currently planned 2011 qualified pension plan contributions, of which Generation, ComEd and PECO contributed $952 million, $871 million and $110 million, respectively. Exelon plans to contribute $11 million to its non-qualified pension plans throughout 2011, of which Generation, ComEd and PECO will contribute $5 million, $2 million and $1 million, respectively.

Unlike the qualified pension plans, Exelon's other postretirement plans are not subject to regulatory minimum contribution requirements. Management considers several factors in determining the level of contributions to Exelon's 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). Exelon expects to contribute approximately $271 million to the other postretirement benefit plans in the fourth quarter of 2011, of which Generation, ComEd and PECO expect to contribute $118 million, $105 million and $28 million, respectively.

Plan Assets

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

In the second quarter of 2010, Exelon modified its pension investment strategy in order to reduce the volatility of its pension assets relative to its pension liabilities. As a result of this modification, over time, Exelon determined that it will decrease equity investments and increase investments in fixed income securities and alternative investments in order to achieve a balanced portfolio of risk-reducing and return-seeking assets. 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. Exelon currently has a target asset allocation of approximately 30% public equity investments, 50% fixed income investments and 20% alternative investments. The change in the overall investment strategy would tend to lower the expected rate of return on plan assets in future years as compared to the previous strategy.

Securities Lending Programs. The majority of the benefit plans currently participate in a securities lending program with the trustees of the plans' investment trusts. Under the program, securities loaned to the trustees are required to be collateralized by cash, U.S. Government securities or irrevocable bank letters of credit. Initial collateral levels are no less than 102% and 105% of the market value of the borrowed securities for collateral denominated in U.S. and foreign currency, respectively. Subsequent collateral levels must be maintained at a level no less than 100% of the market value of borrowed securities. Cash collateral received may not be sold or re-pledged by the trustees unless the borrower defaults.

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

In 2008, Exelon decided to end its participation in this securities lending program and initiated a gradual withdrawal of the trusts' investments in order to minimize potential losses due to liquidity constraints in the market. Currently, the weighted average maturity of the securities within the collateral funds is approximately 12 months. The fair value of securities on loan was approximately $15 million and $46 million at September 30, 2011 and December 31, 2010, respectively. The fair value of cash and non-cash collateral received for these loaned securities was $16 million at September 30, 2011 and $47 million at December 31, 2010. A portion of the income generated through the investment of cash collateral is remitted to the borrowers, and the remainder is allocated between the trusts and the trustees in their capacity as security agents.

401(k) Savings Plan

The Registrants participate in a 401(k) savings plan sponsored by Exelon. The plan allows employees to contribute a portion of their income in accordance with specified guidelines. Exelon, Generation, ComEd and PECO match a percentage of the employee contributions up to certain limits. The following table presents the cost of matching contributions to the savings plans for the Registrants during the three and nine months ended September 30, 2011 and 2010:

Savings Plan Matching Contributions	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Exelon	$ 26	$ 20	$ 64	$ 61
Generation	13	10	33	31
ComEd	8	6	18	17
PECO	3	2	7	7

11. Plant Retirements (Exelon and Generation)

On December 8, 2010, in connection with the executed Administrative Consent Order (ACO) with the NJDEP, Exelon announced that Generation will permanently cease generation operations at Oyster Creek in 2019. See Note 13 for additional information regarding the closure of Oyster Creek.

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 that date 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; however, Cromby Unit 2 will retire on December 31, 2011 and Eddystone Unit 2 will retire 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 and Cromby Unit 2 is approximately $6 million and $2 million, respectively. Such revenue is intended to recover total expected operating costs, plus a return on net assets, of the two units during the reliability-must-run period. In addition, Generation is 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 and Cromby Unit 2 began operating under the reliability-must-run agreement effective June 1, 2011.

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

In connection with the retirement of all four units, Exelon is eliminating 253 employee positions, the majority of which are located at the units to be retired. Total expected costs for Generation related to the announced retirements is $37 million, which includes $14 million for estimated salary continuance and health and welfare severance benefits, a $17 million write down of inventory and $6 million of shut down costs. Cash payments under this plan began in January 2010 and will continue through 2013.

Since the announced retirements in December 2009, Generation recorded pre-tax expense of $29 million, which included a $12 million charge for estimated salary continuance and health and welfare severance benefits, and $17 million of expense for the write down of inventory recorded within operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations.

During the nine months ended September 30, 2011, Generation recorded pre-tax expense of $3 million for estimated salary continuance and health and welfare severance benefits. During the nine months ended September 30, 2010, Generation recorded a pre-tax credit of $2 million for a reduction in estimated salary continuance and health and welfare severance benefits.

The following table presents the activity of severance obligations for the announced Cromby and Eddystone retirements from December 31, 2010 through September 30, 2011:

Severance Benefits Obligation	Exelon and Generation
Balance at December 31, 2010	$ 7
Severance charges recorded	3
Cash payments	(3)
Balance at September 30, 2011	$ 7

12. 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 long-term incentive plans 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 used in calculating diluted earnings per share:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net income	$ 601	$ 845	$ 1,889	$ 2,039
Average common shares outstanding — basic	663	662	663	661
Assumed exercise of stock options, performance share awards and restricted stock	2	1	1	1
Average common shares outstanding — diluted	665	663	664	662

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 10 million and 9 million for the three and nine months ended September 30, 2011, respectively, and 9 million and 8 million for the three and nine months ended September 30, 2010, 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, 2011. In 2008, Exelon management decided to defer indefinitely any share repurchases.

13. Commitments and Contingencies (Exelon, Generation, ComEd and PECO)

For information regarding capital commitments at December 31, 2010, see Note 18 of the 2010 Form 10-K. All significant changes in Exelon's, Generation's, ComEd's and PECO's commitments from December 31, 2010, and all significant contingencies, are disclosed below.

Energy Commitments

Generation's, ComEd's and PECO's short and long-term commitments relating to the sale and purchase of energy, capacity and transmission rights as of September 30, 2011 changed from December 31, 2010 as follows:

- Generation's total commitments for future sales of energy to third parties increased by approximately $500 million during the nine months ended September 30, 2011, reflecting increases of approximately $658 million, $539 million, $185 million, $64 million and $238 million related to 2012, 2013, 2014, 2015 and beyond sales commitments, respectively, partially offset by a net decrease of approximately $1,184 million in 2011 due to the fulfillment of commitments, net of new commitments entered into during the nine months ended September 30, 2011. The increases were primarily due to increased overall hedging activity in the normal course of business. See Note 6 — Derivative Financial Instruments for additional information regarding Generation's hedging program.
- Generation's total commitments for future net purchases of capacity from third parties decreased by $855 million during the nine months ended September 30, 2011, reflecting decreases of approximately $65 million, $66 million, $71 million, $66 million and $350 million related to 2012, 2013, 2014, 2015 and beyond net purchase commitments, respectively, due to overall hedging activity in the normal course of business. A decrease of approximately $237 million related to 2011 commitments was due to the fulfillment of commitments, net of new commitments entered into during the nine months ended September 30, 2011. See Note 6 — Derivative Financial Instruments for additional information regarding Generation's hedging program.
- In May 2011, the ICC approved procurement contracts that enable ComEd to meet its customers' electricity requirements through May 2012 as well as a portion of the requirements for each of the years ending in May 2013 and May 2014. These contracts resulted in an increase in ComEd's energy commitments of $70 million for the remainder of 2011, $192 million for 2012, $292 million for 2013 and $179 million for 2014. See Note 3 — Regulatory Matters for additional information.
- In May and September 2011, PECO entered into procurement contracts in order to meet a portion of its customers' electric supply requirements for 2011 through 2013 that increased PECO's total purchase commitments by $1 million for the remainder of 2011, $335 million for 2012, and $92 million for 2013. See Note 3 — Regulatory Matters for additional information.

Fuel and Natural Gas Purchase Obligations

Generation's and PECO's fuel purchase obligations as of September 30, 2011 changed from December 31, 2010 as follows:

- Generation's total fuel purchase obligations for nuclear and fossil generation decreased $1,061 million during the nine months ended September 30, 2011, primarily due to the fulfillment of fuel procurement contracts in 2011.
- PECO's total natural gas purchase obligations increased by approximately $136 million during the nine months ended September 30, 2011, reflecting increases of $49 million, $72 million, and $15 million for the remainder of 2011, 2012, and 2016 and beyond, respectively, primarily related to increased natural gas purchase commitments made in accordance with PECO's PAPUC-approved procurement schedule.

Commercial and Construction Commitments

Exelon's, Generation's and ComEd's commercial and construction commitments as of September 30, 2011, representing commitments potentially triggered by future events changed from December 31, 2010 as follows:

- Exelon's letters of credit decreased $77 million due to activity at Generation, ComEd and PECO as discussed below. Guarantees decreased by $53 million predominantly as a result of the termination of an Exelon guarantee to the NRC, net of energy trading activities at Generation as noted below. Guarantees decreased by $55 million for 2011, increased by $176 million for 2012, increased by $28 million for 2013 and decreased by $202 million for 2016 and beyond.
- Generation's letters of credit decreased by $73 million and guarantees increased by $170 million primarily as a result of energy trading activities.
- Generation's construction commitments increased by $195 million, $528 million and $445 million for 2011, 2012 and 2013, respectively, due to Generation's commitment to construct a 230 MW solar project in Lancaster, California, as further described in Note 4 — Merger and Acquisitions.
- ComEd's letters of credit decreased by $4 million primarily due to a decrease in the letter of credit required as collateral for ComEd's workers compensation self-insurance.
- ComEd's PJM RTEP baseline project commitments decreased by $(21) million for the nine months ended September 30, 2011, reflecting increases (decreases) of $32 million, $13 million, $(22) million, $(19) million and $(25) for 2011, 2012, 2013, 2014 and 2015, respectively, driven by changes in estimated timing and amount of project spending.
- PECO's PJM RTEP baseline project commitments increased by $ 10 million for the nine months ended September 30, 2011, reflecting increases (decreases) of $ (9) million, $ 9 million, and $ 10 million for 2013, 2014, and 2015, respectively, driven by changes in estimated timing and amount of project spending.

Other Purchase Obligations

Exelon's, Generation's, ComEd's and PECO's other purchase obligations as of September 30, 2011, which primarily represent commitments for services, materials and information, changed from December 31, 2010 as follows:

- Exelon's other purchase obligations increased (decreased) by $(4) million, $46 million, $7 million, $64 million, $55 million and $11 million for 2011, 2012, 2013, 2014, 2015 and 2016 and beyond, respectively.

- Generation's other purchase obligations increased (decreased) by $(12) million, $11 million, $9 million, $64 million, $55 million, and $5 million for 2011, 2012, 2013, 2014, 2015 and 2016 and beyond, respectively.
- ComEd's other purchase obligations increased (decreased) by $(13) million and $8 million for 2011 and 2012, respectively.
- PECO's other purchase obligations increased by $20 million, $29 million, $2 million and $6 million for 2011, 2012, 2013 and 2016 and beyond, respectively.

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, Exelon 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, 2011.

Indemnifications Related to Sale of Termoeléctrica del Golfo (TEG) and Termoeléctrica Peñoles (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, 2011. Generation has not recorded a liability associated with this guarantee. The exposures covered by this guarantee expired in part during 2008. Generation expects that the remaining exposure will expire by 2014.

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 and PECO have identified 42 and 27 sites, respectively, where former MGP activities have or may have resulted in actual site contamination. For almost all of these sites, ComEd or PECO is one of several PRPs that may be responsible for ultimate remediation of each location. Of the 42 sites identified by ComEd, the

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Illinois EPA or U.S. EPA have approved the cleanup of 12 sites and of the 27 sites identified by PECO, the PA DEP has approved the cleanup of 16 sites. Of the remaining sites identified by ComEd and PECO, 27 and 11 sites, respectively, are currently under some degree of active study and/or remediation. ComEd and PECO anticipate that the majority of the remediation at these sites will continue through at least 2016 and 2019, respectively.

Pursuant to orders from the ICC and PAPUC, respectively, ComEd and PECO 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 third quarter of 2011, ComEd and PECO each 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 $14 million and $7 million, respectively. See Note 3 — Regulatory Matters for additional information regarding the associated regulatory assets.

As of September 30, 2011 and December 31, 2010, the Registrants had accrued the following undiscounted amounts for environmental liabilities in other deferred credits and other liabilities within their Consolidated Balance Sheets:

September 30, 2011	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 228	$ 174
Generation	46	—
ComEd	129	124
PECO	53	50

December 31, 2010	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 179	$ 156
Generation	15	—
ComEd	120	114
PECO	44	42

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 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. Those facilities are Clinton, Dresden, Fairless Hills, Handley, Mountain Creek, Oyster Creek, Peach Bottom, Quad Cities, Salem and Schuylkill. See Item 2 of Exelon's 2010 Form 10-K for a description of these facilities.

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

On March 28, 2011, the 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 similar 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. Pursuant to a court approved Settlement Agreement, the EPA is required to approve the final rule by July 27, 2012. 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 December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by 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, in its best professional judgment, 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 the ACO, the NJDEP agreed to issue a new draft NPDES permit without a requirement for construction of cooling towers or other closed cycle cooling facilities. On June 1, 2011, the NJDEP issued a draft permit that does not require the installation of cooling towers and is otherwise consistent with the terms of the ACO. The ACO applies 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 has been reduced. 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. During the nine months ended September 30, 2011, Generation made employee retention payments of approximately $14 million that will result in approximately $3 million of expense in each of years 2011 through 2015. During the nine months ended September 30, 2011, Generation recorded approximately $2 million of employee retention expense.

Salem and Other Power Generation Facilities. In June 2001, the NJDEP issued a renewed NPDES permit for Salem, allowing for the continued operation of Salem with its existing cooling water system. NJDEP advised PSEG in July 2004 that it strongly recommended reducing cooling water intake flow commensurate with closed-cycle cooling as a compliance option for Salem. PSEG submitted an application for a renewal of the permit on February 1, 2006. In the permit renewal application, PSEG analyzed closed-cycle cooling and other options and demonstrated that the continuation of the Estuary Enhancement Program, an extensive environmental restoration program at Salem, is the best technology to meet the Section 316(b) requirements. PSEG continues to operate Salem under the approved June 2001 NPDES permit while the NPDES permit renewal application is being reviewed. If the final permit or Section 316(b) regulations ultimately requires the retrofitting of Salem's cooling water intake structure to reduce cooling water intake flow commensurate with closed-cycle cooling, Exelon 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 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.

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 generating facilities and its future results of operations, cash flows and financial position.

Conemaugh Station Water Discharge Violation. In April 2007, two environmental groups brought a Clean Water Act citizen suit against the operator of Conemaugh Generating Station (CGS), seeking civil penalties and injunctive relief for alleged violations of CGS's NPDES permit. On March 21, 2011, the court entered a partial summary judgment in the plaintiffs' favor, declaring as a matter of law that discharges from CGS had violated the NPDES permit. On June 6, 2011, the operator of CGS signed and entered with the court a settlement and consent decree with the plaintiffs. Under the consent decree, CGS will pay a total of $5 million, of which Generation's share is $1 million (equivalent to its 20.72% share of CGS).

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 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 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 Cross-State Air Pollution Rule (CSAPR). The CSAPR requires 27 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 2011 — 2012 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. As of September 30, 2011, Generation had $4 million of emission allowances carried at the lower of weighted average cost or market. Numerous entities have challenged the CSAPR in the D.C. Circuit Court, and some have requested a stay of the rule pending that Court's consideration of the matter on the merits. Exelon believes that the CSAPR is a valid exercise of the U.S. EPA's authority and discretion under the CAA. The D.C. Circuit Court has granted permission for Exelon, as well as a number of other parties, to intervene in the litigation in support of the rule and in opposition to a stay of the rule. The Court has not set a case management schedule, and it is therefore unknown when the litigation will be resolved.

On October 14, 2011, the 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.

EPA Toxics Rule. In March 2005, the U.S. EPA finalized the CAMR, which was a national program to cap mercury emissions from fossil-fired generating units starting in 2010, with a second reduction in the mercury emission cap level scheduled for 2018. The D.C. Circuit Court later vacated the CAMR on the basis that the U.S. EPA had failed to properly de-list mercury as a HAP under Section 112(c)(1) of the Clean Air Act. The result of this decision is that mercury emissions from electric generating stations are subject to the more stringent requirements of maximum achievable control technology applicable to HAPs. In resolution of the CAMR litigation, the U.S. EPA entered into a Consent Decree that required it to propose by March 16, 2011 HAP regulations for emissions from fossil generating stations, and to publish final HAP regulations by November 15, 2011.

On March 16, 2011, the U.S. EPA issued a proposed rule setting national emission standards for HAPs from coal- and oil-fired electric generating facilities. EPA refers to the rule as "the Toxics Rule." The Toxics Rule would require coal-fired electric generation plants 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 units will retire rather than make these investments. Coal units with existing controls that do not meet the Toxics Rule may need to upgrade existing controls or add new controls to comply. Exelon, along with the other co-owners of Conemaugh Generating Station, are evaluating controls needed to comply with the Toxics Rule. EPA's proposed 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 nature and extent of future regulatory controls on HAP emissions at electric generation power plants will not be determined until the Toxics Rule is finalized by the EPA in December 2011.

The U.S. EPA previously announced that it would complete a review of NAAQS in the 2011 — 2012 timeframe for particulate matter, nitrogen dioxide, sulfur dioxide, and lead. This review could result in more stringent emissions limits on fossil-fired electric generating stations. In September 2011, the U.S. EPA withdrew its reconsideration of the NAAQS standard for ozone, which is next scheduled for reconsideration in 2013.

Additionally, as of September 30, 2011, Exelon has a $649 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases that extend 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 HAP 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.

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 U.S. EPA requested information related to the stations in 2003, and ComEd has been cooperating with the U.S. EPA since then. The NOV states that the U.S. EPA may issue an order requiring compliance with the relevant Clean Air Act provisions and may seek injunctive relief and/or civil penalties, all pursuant to the U.S. EPA's enforcement authority under the Clean Air Act.

The generating stations that are the subject of the NOV 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. The dismissal order will not be final until the underlying case against Midwest Generation is resolved, so the government plaintiffs cannot appeal ComEd's dismissal before that time without leave of court. The government plaintiffs have requested an appeal conditional upon a stay of the remaining case until the appeal is completed. A ruling on the merits of allowing a stay is set for November 10, 2011.

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.

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. Cotter is alleged to have disposed of approximately 39,000 tons of soils mixed with 8,700 tons of leached barium sulfate at the site. 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 EPA for review. 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 1967 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $100 million. The DOJ and the PRPs have agreed to toll the statute of limitations until August 2012 so that settlement discussions can proceed. 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.

Climate Change Regulation

Exelon is, or may become, subject to climate change regulation or legislation at the international, Federal, regional and state levels.

International Climate Change Regulation. At the international level, the United States is currently not a party to the Kyoto Protocol, which is a protocol to the United Nations Framework Convention on Climate Change (UNFCCC) and became effective for signatories on February 16, 2005. The United Nations' Kyoto Protocol process generally requires developed countries to cap GHG emissions at certain levels during the 2008-2012 time period. At the conclusion of the December 2007 United Nations Climate Change Conference in Bali, Indonesia, the Bali Action Plan was adopted, which identifies a work group, process and timeline for the consideration of possible post-2012 international actions to further address climate change. In December 2009, the United States agreed to the non-binding Copenhagen Accord at the conclusion of the 15th Conference of the Parties under the UNFCCC. Under the Copenhagen Accord, the United States agreed to undertake a number of voluntary measures, including the establishment of a goal to reduce GHG emissions and contributions toward a fund to assist developing nations to address their GHG emissions. The Conference of the Parties met in Mexico in December 2010 and while some progress was made in the Cancun Agreement, the fundamental issues around GHG emission reductions and a successor to the Kyoto Protocol remain unresolved. The next Conference of the Parties meeting will be held in December 2011 in South Africa.

Federal Climate Change Legislation and Regulation. Various stakeholders, including Exelon, legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors are considering ways to address the climate change issue. Mandatory programs to reduce GHG emissions are likely to evolve in the future. If these programs become effective, Exelon may incur costs either to further limit or offset the GHG emissions from its operations or procure emission allowances or credits.

Numerous bills were introduced in Congress during the 111th Congress that address climate change from different perspectives, including direct regulation of GHG emissions and the establishment of Federal Renewable Portfolio Standards, but none were passed by both houses of Congress. In reaction to the U.S. EPA's proposed regulation of GHG emissions, various bills have been introduced in the U.S. House of Representatives that would prohibit or impede the U.S. EPA's rulemaking efforts. The timing of the consideration of such legislation is unknown.

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 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. Under the 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 could be significantly affected by the regulations if it were to build new plants or modify existing plants. In addition EPA is preparing a proposed rule to establish new source performance standards for greenhouse gas emissions from power plants as part of a court settlement.

The issue of GHG regulation of stationary sources will likely be addressed either under the existing provisions of the Clean Air Act by U.S. EPA regulation, or by new and comprehensive Federal legislation. The Obama administration and the U.S. EPA have stated a preference for addressing the issue through Federal legislation. The extent to which GHG emissions will be regulated is currently unknown; however, potential regulation of GHG emissions from stationary sources could cause Exelon to incur material costs of compliance.

Regional and State Climate Change Legislation and Regulation. At a regional level, on November 15, 2007, six Midwest state Governors (Illinois, Iowa, Kansas, Michigan, Minnesota and Wisconsin) signed the Midwestern Greenhouse Gas Accord. Under that Accord, an inter-state work group was formed to establish a Midwestern GHG Reduction Program that will: (1) establish GHG reduction targets and timeframes consistent with member state targets; (2) develop a market-based and multi-sector cap-and-trade program to help achieve GHG reductions; and (3) develop other mechanisms and policies to assist in meeting GHG reduction targets (e.g. a low carbon fuel standard). In May 2010, an advisory group appointed by the Governors issued recommendations, but no actions have been taken on the recommendations.

At the state level, the PCCA was signed into law in Pennsylvania in July 2008. The PCCA requires, among other things, that: a Climate Change Advisory Committee be formed; a report on the potential impact of climate change in Pennsylvania be developed; the PA DEP develop a GHG inventory for Pennsylvania; a voluntary GHG registry be identified; and the PA DEP, in consultation with the Climate Change Advisory Committee, develop a Climate Change Action Plan for Pennsylvania to be reviewed with the Pennsylvania General Assembly. The Climate Change Advisory Committee issued its recommendations for an Action Plan for consideration by the Pennsylvania legislature on October 9, 2009.

Litigation Matters

Except to the extent noted below, the circumstances set forth in Note 18 of the 2010 Form 10-K describe, in all material respects, the current status of litigation matters. The following is an update to that discussion.

Exelon and Generation

Asbestos Personal Injury Claims. 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, 2011 and December 31, 2010, Generation had reserved approximately $51 million in total for asbestos-related bodily injury claims. As of September 30, 2011, approximately $15 million of this amount related to 178 open claims presented to Generation, while the remaining $36 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.

Exelon

Savings Plan Claim. On September 11, 2006, five individuals claiming to be participants in the Exelon Corporation Employee Savings Plan, Plan #003 (Savings Plan), filed a putative class action lawsuit in the U.S. District Court for the Northern District of Illinois. The complaint names as defendants Exelon, its Director of Employee Benefit Plans and Programs, the Employee Savings Plan Investment Committee, the Compensation and the Risk Oversight Committees of Exelon’s Board of Directors and members of those committees. On December 9, 2009, the District Court granted the defendants’ motion to dismiss the amended complaint and enter judgment in favor of the defendants. The plaintiffs appealed the District Court’s dismissal of their claims to the U.S. Court of Appeals for the Seventh Circuit who affirmed the dismissal of the class action lawsuit on September 6, 2011. The plaintiffs have 90 days to file a petition requesting that the case be heard by the U.S. Supreme Court. While Exelon believes it will prevail, the ultimate outcome of the savings plan claim is uncertain, cannot be estimated and it may have a material impact on Exelon’s results of operations, cash flows or financial position.

Exelon, Generation, ComEd and PECO

General. The Registrants are involved in various other individually immaterial litigation matters 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

See Note 8 — Income Taxes for information regarding the Registrants’ income tax refund claims and uncertain 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)

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

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants' Consolidated Statements of Operations for the three and nine months ended September 30, 2011 and 2010:

Three Months Ended September 30, 2011	Exelon	Generation	ComEd	PECO
Depreciation, amortization and accretion				
Property, plant and equipment	$ 319	$ 139	$ 125	$ 48
Regulatory assets	13	—	10	3
Nuclear fuel(a)	200	200	—	—
Asset retirement obligation accretion(b)	56	56	—	—
Total depreciation, amortization and accretion	$ 588	$ 395	$ 135	$ 51

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

Three Months Ended September 30, 2010	Exelon	Generation	ComEd	PECO
Depreciation, amortization and accretion				
Property, plant and equipment	$ 288	$ 121	$ 119	$ 43
Regulatory assets(c)	290	—	7	283
Nuclear fuel(a)	173	173	—	—
Asset retirement obligation accretion(b)	49	49	—	—
Total depreciation, amortization and accretion	$ 800	$ 343	$ 126	$ 326

Nine Months Ended September 30, 2010	Exelon	Generation	ComEd	PECO
Depreciation, amortization and accretion				
Property, plant and equipment	$ 845	$ 344	$ 352	$ 128
Regulatory assets(c)	766	—	34	731
Nuclear fuel(a)	496	496	—	—
Asset retirement obligation accretion(b)	148	147	1	—
Total depreciation, amortization and accretion	$ 2,255	$ 987	$ 387	$ 859

(a) Included in fuel expense 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.
(c) For PECO, primarily reflects CTC amortization.

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

Three Months Ended September 30, 2011	Exelon	Generation	ComEd	PECO
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
Long-term lease income	7	—	—	—
Interest income related to uncertain income tax positions	7	—	12	—
AFUDC — Equity	4	—	2	2
Bargain purchase gain related to Wolf Hollow acquisition	36	36	—	—
Other	—	(2)	2	—
Other, net	$(143)	$ (164)	$ 16	$ 3

Nine Months Ended September 30, 2011	Exelon	Generation	ComEd	PECO
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
Long-term lease income	21	—	—	—
Interest income related to uncertain income tax positions	53	33	13	1
AFUDC — Equity	14	—	6	8
Bargain purchase gain related to Wolf Hollow acquisition	36	36	—	—
Other	(2)	(7)	5	(1)
Other, net	$ 51	$ (12)	$ 24	$ 11

(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 and income taxes related to all NDT fund activity for these units. Also, includes the elimination of unrealized gains and losses on the Zion Station pledged assets. See Note 12 of the 2010 Form 10-K for additional information regarding the accounting for nuclear decommissioning.

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

Three Months Ended September 30, 2010	Exelon	Generation	ComEd	PECO
Other, Net				
Decommissioning-related activities:				
Net realized income on decommissioning trust funds(a) — Regulatory Agreement Units	$ 41	$ 41	$ —	$ —
Non-Regulatory Agreement Units	12	12	—	—
Net unrealized losses on decommissioning trust funds —				
Regulatory Agreement Units	324	324	—	—
Non-Regulatory Agreement Units	107	107	—	—
Regulatory offset to decommissioning trust fund-related activities(b)	(292)	(292)	—	—
Total decommissioning-related activities	192	192	—	—
Long-term lease income	7	—	—	—
Interest income related to uncertain income tax positions	—	—	1	—
AFUDC — Equity	2	—	—	2
Other	5	—	2	1
Other, net	$ 206	$ 192	$ 3	$ 3

Nine Months Ended September 30, 2010	Exelon	Generation	ComEd	PECO
Other, Net				
Decommissioning-related activities:				
Net realized income on decommissioning trust funds(a) — Regulatory Agreement Units	$ 140	$ 140	$ —	$ —
Non-Regulatory Agreement Units	38	38	—	—
Net unrealized losses on decommissioning trust funds —				
Regulatory Agreement Units	117	117	—	—
Non-Regulatory Agreement Units	48	48	—	—
Regulatory offset to decommissioning trust fund-related activities(b)	(206)	(206)	—	—
Total decommissioning-related activities	137	137	—	—
Long-term lease income	20	—	—	—
Interest income related to uncertain income tax positions	—	—	3	—
AFUDC — Equity	6	—	1	5
Other	15	1	10	1
Other, net	$ 178	$ 138	$ 14	$ 6

(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 2010 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, 2011 and 2010:

Nine Months Ended September 30, 2011	Exelon	Generation	ComEd	PECO
Other non-cash operating activities:				
Pension and non-pension postretirement benefit costs	$ 407	$ 187	$ 160	$ 24
Provision for uncollectible accounts	97	—	49	48
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
Uncollectible accounts recovery, net	14	—	14	—
Discrete impacts from 2010 Rate Case order(c)	(32)	—	(32)	—
Bargain purchase gain related to Wolf Hollow Acquisition	(36)	(36)	—	—
Other	18	47	5	—
Total other non-cash operating activities	$ 703	$ 362	$ 210	$ 74
Changes in other assets and liabilities:				
Under-recovered energy and transmission costs	(9)	—	(20)	11
Other current assets	(163)	(46)	(13)	(59)(d)
Other noncurrent assets and liabilities	83	(19)	62	20
Total changes in other assets and liabilities	$ (89)	$ (65)	$ 29	$ (28)

Nine Months Ended September 30, 2010	Exelon	Generation	ComEd	PECO
Other non-cash operating activities:				
Pension and non-pension postretirement benefit costs	$ 435	$ 202	$ 161	$ 35
Provision for uncollectible accounts	92	—	44	48
Stock-based compensation costs	35	—	—	—
Other decommissioning-related activity(a)	(46)	(46)	—	—
Energy-related options(b)	(54)	(54)	—	—
Amortization of regulatory asset related to debt costs	18	—	15	3
Accrual for Illinois utility distribution tax refund(e)	(25)	—	(25)	—
Uncollectible accounts recovery, net(f)	(36)	—	(36)	—
Impairment of certain emission allowances	57	57	—	—
Other	(8)	5	3	(1)
Total other non-cash operating activities	$ 468	$ 164	$ 162	$ 85
Changes in other assets and liabilities:				
Under/over-recovered energy and transmission costs	154	—	151	3
Other current assets	(81)	(46)	10	(51)(d)
Other noncurrent assets and liabilities	(114)	(6)	(247)(g)	84
Total changes in other assets and liabilities	$ (41)	$ (52)	$ (86)	$ 36

(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 2010 Form 10-K for additional information regarding the accounting for nuclear decommissioning.

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

(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) 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 3 — Regulatory Matters for more information.
(d) Relates primarily to prepaid utility taxes.
(e) During the second quarter of 2010, ComEd recorded a reduction of $25 million to taxes other than income to reflect management's estimate of future refunds for the 2008 and 2009 tax years associated with Illinois' utility distribution tax based on an analysis of past refunds and interpretations of the Illinois Public Utilities Act. Historically, ComEd had recorded refunds of the Illinois utility distribution tax when received. ComEd believes it now has sufficient, reliable evidence to record and support an estimated receivable associated with the anticipated refund for the 2008 and 2009 tax years.
(f) Includes $70 million of under-recovered uncollectible accounts expense from 2008 and 2009 recoverable prospectively through a rider mechanism as a result of an ICC order issued February 2010. See Note 3 — Regulatory Matters for additional information regarding the Illinois legislation allowing recovery of uncollectible accounts.
(g) Relates primarily to a decrease in interest payable associated with a change in uncertain income tax positions. See Note 8 — Income Taxes for additional information.

DOE Smart Grid Investment Grant (Exelon and PECO). For the nine months ended September 30, 2011, Exelon and PECO have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $29 million and reimbursements of $45 million related to PECO's DOE SGIG. See Note 3 — Regulatory Matters for additional information regarding the DOE SGIG.

Repurchase Agreements (Exelon and Generation). Repurchase Agreements are financial instruments used to fund short-term liquidity requirements where a counterparty typically agrees to sell the financial instrument and repurchase it the following day. Exelon and Generation have historically presented purchases and sales of Repurchase Agreements with a maturity of three months or less on a gross basis in 'Investments in NDT funds' and 'Proceeds from NDT fund sales', respectively, within Exelon and Generation's Consolidated Statements of Cash Flows. Due to the nature and volume of these transactions, effective December 31, 2010, Exelon and Generation have included the cash flows associated with the purchase and sale of Repurchase Agreements with a maturity of three months or less on a net basis in 'Proceeds from NDT fund sales' within their Consolidated Statements of Cash Flows. Cash flows associated with all other NDT funds investments will continue to be presented on a gross basis. The nine months ended September 30, 2010 was adjusted to reflect this change in presentation, which is presented in the following table:

	Nine Months Ended September 30, 2010		
	As previously stated	Adjustments	As Adjusted
Proceeds from NDT fund sales	$ 21,869	$ (19,113)	$ 2,756
Investments in NDT funds	$ (21,977)	$ 19,113	$ (2,864)

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

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants as of September 30, 2011 and December 31, 2010.

September 30, 2011	Exelon	Generation	ComEd	PECO
Property, plant and equipment:				
Accumulated depreciation	$10,919(a)	$ 5,394(a)	$2,672	$2,624
Accounts receivable:				
Allowance for uncollectible accounts	244	30	90	124

December 31, 2010	Exelon	Generation	ComEd	PECO
Property, plant and equipment:				
Accumulated depreciation	$10,064(b)	$ 4,880(b)	$2,428	$2,531
Accounts receivable:				
Allowance for uncollectible accounts	228	32	80	116

(a) Includes accumulated amortization of nuclear fuel in the reactor core of $1,880 million.
(b) Includes accumulated amortization of nuclear fuel in the reactor core of $1,592 million.

PECO Installment Plan Receivables (Exelon and PECO). PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $23 million and $22 million as of September 30, 2011 and December 31, 2010, respectively. 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 2010 Form 10-K. As of September 30, 2011, the allowance for uncollectible accounts was $20 million, an increase of $1 million from December 31, 2010. The increase is the result of the change in the provision, which is impacted by payments, new agreements, changes in account risk segments and loss factors applied to the risk segments. The allowance for uncollectible accounts balance at September 30, 2011 of $20 million consists of $4 million and $16 million for medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2010 of $19 million consists of $1 million, $5 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, 2011 and December 31, 2010 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 2010 Form 10-K.

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

The following tables provide information about accumulated OCI (loss) recorded (after tax) within the Consolidated Balance Sheets of the Registrants as of September 30, 2011 and December 31, 2010:

September 30, 2011	Exelon	Generation	ComEd	PECO
Accumulated other comprehensive income (loss)				
Net unrealized gain on cash flow hedges	$ 145	$ 565	$ —	$ —
Pension and non-pension postretirement benefit plans	(2,685)	—	—	—
Unrealized loss on marketable securities	—	—	(1)	—
Total accumulated other comprehensive income (loss)	$(2,540)	$ 565	$ (1)	$ —

December 31, 2010	Exelon	Generation	ComEd	PECO
Accumulated other comprehensive income (loss)				
Net unrealized gain on cash flow hedges	$ 400	$ 1,013	$ —	$ —
Pension and non-pension postretirement benefit plans	(2,823)	—	—	—
Unrealized loss on marketable securities	—	—	(1)	—
Total accumulated other comprehensive income (loss)	$(2,423)	$ 1,013	$ (1)	$ —

15. Segment Information (Exelon, Generation, ComEd and PECO)

Exelon has five reportable segments, which include Generation's three reportable segments consisting of the Mid-Atlantic, Midwest, and South and West, and ComEd and PECO. ComEd and PECO each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. PECO has two operating segments, electric and gas delivery, which are aggregated into one reportable segment primarily due to their similar economic characteristics and the regulatory environments in which they operate.

Exelon and Generation evaluate the performance of Generation's power marketing activities in the Mid-Atlantic, Midwest, and South and West 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 and PECO. 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 retail gas, proprietary trading, compensation under the reliability-must-run rate schedule, other revenues and mark-to-market activities are not allocated to a region. Exelon and Generation do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments. Exelon evaluates the performance of ComEd and PECO based on net income.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(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, 2011 and 2010 is as follows:

Three Months Ended September 30, 2011 and 2010

	Generation(a)	ComEd	PECO	Other	Intersegment Eliminations	Exelon
Total revenues(b):						
2011	$ 2,862	$ 1,784	$ 946	$ 206	$ (503)	$ 5,295
2010	2,655	1,918	1,495	183	(960)	5,291
Intersegment revenues(c):						
2011	$ 304	$ 1	$ 2	$ 203	$ (503)	$ 7
2010	778	—	1	183	(959)	3
Net income (loss):						
2011	$ 386	$ 112	$ 105	$ (2)	$ —	$ 601
2010	605	121	127	(8)	—	845
Total assets:						
September 30, 2011	$ 26,086	$22,983	$9,336	$6,014	$ (10,263)	$54,156
December 31, 2010	24,534	21,652	8,985	6,651	(9,582)	52,240

(a) Generation represents the three segments, Mid-Atlantic, Midwest, and South and West as shown below. Intersegment revenues for the three months ended September 30, 2011 and 2010, represent Mid-Atlantic revenue from sales to PECO of $145 million and $576 million, respectively, and Midwest revenue from sales to ComEd of $159 million and $202 million, respectively.

(b) For the three months ended September 30, 2011 and 2010, utility taxes of $64 million and $67 million, respectively, are included in revenues and expenses for ComEd. For the three months ended September 30, 2011 and 2010, utility taxes of $50 million and $80 million, respectively, are included in revenues and expenses for PECO.

(c) 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 2010 Form 10-K for additional information on AECs. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations.

	Mid-Atlantic	Midwest	South and West	Other(b)	Generation
Total revenues(a):					
2011	$ 1,020	$1,365	$ 384	$ 93	$ 2,862
2010	814	1,526	282	33	2,655
Revenues net of purchased power and fuel expense:					
2011	$ 836	$ 853	$ 98	$ (37)	$ 1,750
2010	564	1,044	(11)	113	1,710

(a) Includes all sales to third parties and affiliated sales to ComEd and PECO. For the three months ended September 30, 2011 and 2010, there were no transactions among Generation's reportable segments which would result in intersegment revenue for Generation.

(b) Includes retail gas, proprietary trading, compensation under the reliability-must-run rate schedule, other revenues, mark-to-market activities and the impairment of certain emission allowances in 2010.

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

Nine Months Ended September 30, 2011 and 2010

	Generation(a)	ComEd	PECO	Other	Intersegment Eliminations	Exelon
Total revenues(b):						
2011	$ 8,147	$4,694	$2,942	$579	$ (1,429)	$14,933
2010	7,428	4,832	4,220	542	(2,872)	14,150
Intersegment revenues(c):						
2011	$ 856	$ 2	$ 4	$576	$ (1,429)	$ 9
2010	2,330	1	4	542	(2,871)	6
Net income (loss):						
2011	$ 1,325	$ 295	$ 314	$ (45)	$ —	$ 1,889
2010	1,548	246	303	(58)	—	2,039

(a) Generation represents the three segments, Mid-Atlantic, Midwest, and South and West as shown below. Intersegment revenues for the nine months ended September 30, 2011 and 2010, represent Mid-Atlantic revenue from sales to PECO of $406 million and $1,504 million, respectively, and Midwest revenue from sales to ComEd of $450 million and $826 million, respectively.

(b) For the nine months ended September 30, 2011 and 2010, utility taxes of $184 million and $147 million, respectively, are included in revenues and expenses for ComEd. For the nine months ended September 30, 2011 and 2010, utility taxes of $140 million and $210 million, respectively, are included in revenues and expenses for PECO.

(c) The intersegment profit associated with Generation's sale of RECs to ComEd and AECs to PECO is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. See Note 3 — Regulatory Issues for additional information on RECs and AECs

	Mid-Atlantic	Midwest	South and West	Other(b)	Generation
Total revenues(a):					
2011	$ 3,069	$4,089	$ 676	$ 313	$ 8,147
2010	2,344	4,259	580	245	7,428
Revenues net of purchased power and fuel expense:					
2011	$ 2,573	$2,704	$ 84	$ (237)	$ 5,124
2010	1,760	3,054	(102)	274	4,986

(a) Includes all sales to third parties and affiliated sales to ComEd and PECO. For the nine months ended September 30, 2011 and 2010, there were no transactions among Generation's reportable segments which would result in intersegment revenue for Generation.

(b) Includes retail gas, proprietary trading, compensation under the reliability-must-run rate schedule, other revenues, mark-to-market activities and the impairment of certain emission allowances in 2010.

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 its owned and contracted electric generating facilities, its wholesale energy marketing operations and competitive retail sales operations.
- *ComEd*, whose business consists of the purchase and regulated retail sale of electricity and the provision of transmission and distribution 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 transmission and distribution services in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.

Exelon has five reportable segments consisting of the Mid-Atlantic, Midwest, and South and West regions in Generation, ComEd and PECO. See Note 15 of the Combined Notes to Consolidated Financial Statements for segment information.

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.

Executive Overview

Financial Results. All amounts presented below are before the impact of income taxes, except as noted.

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Exelon's net income was $601 million for the three months ended September 30, 2011 as compared to $845 million for the three months ended September 30, 2010, and diluted earnings per average common share were $0.90 for the three months ended September 30, 2011 as compared to $1.27 for the three months ended September 30, 2010.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, decreased by $202 million primarily related to a decrease in CTC recoveries at PECO of $351 million as a result of the end of the transition period on December 31, 2010. This impact on Exelon's net income was partially offset by decreased CTC amortization expense discussed below. Mark-to-market losses of $91 million in 2011 from Generation's hedging activities compared to mark-to-market gains of $163 million in 2010 had an unfavorable impact on Generation's operating results. In addition, Generation's operating revenue net of purchased power and fuel expense decreased by $191 million in the Midwest due to lower capacity revenues, lower realized power prices and increased nuclear fuel costs. Offsetting these unfavorable impacts were increased operating revenues net of purchased power and fuel expense at Generation of $272 million in the Mid-Atlantic due to increased realized margins on volumes previously sold under Generation's PPA with PECO, which expired on December 31, 2010, and $109 million in the South and West at Generation primarily driven by favorable pricing as a result of extreme weather and market conditions that occurred in Texas in August 2011. Operating revenue net of purchase power expense and fuel expense at Generation was also impacted favorably by additional revenues from Exelon Wind, which was acquired in December 2010. ComEd's and PECO's operating revenues net of purchased power and fuel expense increased by $44 million and $31 million, respectively, as a result of improved pricing primarily due to the new electric distribution rates effective June 1, 2011 pursuant to ComEd's 2010 Rate Case order and new electric and natural gas distribution rates effective January 1, 2011 pursuant to PECO's approved 2010 electric and natural gas distribution rate case settlements.

Operating and maintenance expense increased by $254 million primarily as a result of increased storm costs in the ComEd and PECO service territories of $67 million and $25 million, respectively, increased labor, other benefits, contracting and materials expenses of $46 million, including Exelon Wind, and the impacts of nuclear refueling outage costs, including the co-owned Salem plant, of $25 million at Generation. The increase was also attributable to a $28 million increase in Generation's decommissioning obligation for spent nuclear fuel at Zion and $29 million of costs related to the acquisitions of Wolf Hollow, Antelope Valley and the proposed merger with Constellation.

Depreciation and amortization expense decreased by $246 million primarily due to a decrease in CTC amortization expense at PECO of $281 million resulting from the end of the transition period on December 31, 2010, partially offset by increased depreciation expense primarily due to additional plant placed in service and the acquisition of Exelon Wind. Exelon's results were also significantly affected by unrealized losses on NDT funds of $141 million in 2011 (compared to unrealized gains of $107 million in 2010) for Non-Regulatory Agreement Units as a result of unfavorable market performance.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Exelon's net income was $1,889 million for the nine months ended September 30, 2011 as compared to $2,039 million for the nine months ended September 30, 2010, and diluted earnings per average common share were $2.84 for the nine months ended September 30, 2011 as compared to $3.08 for the nine months ended September 30, 2010.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, decreased by $539 million primarily related to a decrease in CTC recoveries at PECO of $906 million as a result of the end of the transition period on December 31, 2010. This impact on Exelon's net income was partially offset by decreased CTC amortization expense discussed below. Mark-to-market losses of $363 million in 2011 from Generation's hedging activities compared to $273 million in mark-to-market gains in 2010 also had an unfavorable impact on Generation's operating results. In addition, Generation's operating revenue net of purchased power and fuel expense decreased by $350 million in the Midwest due to decreased realized margins in 2011 for volumes previously sold under the 2006 ComEd auction contracts, higher incurred congestion costs and increased nuclear fuel costs. Offsetting these unfavorable impacts were increased operating revenues net of purchased power and fuel expense at Generation of $813 million in the Mid-Atlantic due to increased realized margins on volumes previously sold under Generation's PPA with PECO, which expired on December 31, 2010, and $186 million in the South and West primarily driven by the performance of Exelon's generating units during extreme weather events that occurred in Texas in February and August 2011. Operating revenue net of purchased power and fuel expense in the South and West was also impacted favorably by additional revenues from Exelon Wind which was acquired in December 2010 and higher realized margins due to favorable market conditions. ComEd's and PECO's operating revenues net of purchased power and fuel expense increased by $57 million and $116 million, respectively, as a result of improved pricing primarily due to the new electric distribution rates effective June 1, 2011 pursuant to ComEd's 2010 Rate Case order and new electric and natural gas distribution rates effective January 1, 2011 pursuant to PECO's 2010 approved electric and natural gas distribution rate case settlements.

Operating and maintenance expense increased by $467 million primarily as a result of increased storm costs in the ComEd and PECO service territories of $72 million and $10 million, respectively, and a $55 million increase in uncollectible accounts expense at ComEd principally due to the impact of the recovery rider mechanism being approved by the ICC in 2010. Exelon's results were also affected by increased labor, other benefits, contracting and materials expenses of $157 million, including Exelon Wind. The increase was also attributable to a $35 million increase in nuclear refueling outage costs, including the co-owned Salem plant, a $28 million increase in Generation's decommissioning obligation for spent nuclear fuel at Zion and $54 million of costs related to the acquisitions of Wolf Hollow, Antelope Valley and the proposed merger with Constellation. These impacts were partially offset by one-time net benefits of $32 million to re-establish plant balances and to recover previously incurred costs related to Exelon's 2009 restructuring plan pursuant to the 2010 ComEd Rate Case order recorded in the second quarter of 2011.

Depreciation and amortization expense decreased by $624 million primarily due to a decrease in CTC amortization expense at PECO of $725 million resulting from the end of the transition period on December 31, 2010, partially offset by increased depreciation expense primarily due to additional plant placed in service and the acquisition of Exelon Wind.

Interest expense decreased by $89 million primarily due to the impact of the 2010 remeasurement of uncertain income tax positions related to the 1999 sale of ComEd's fossil generating assets and CTCs collected by PECO, which resulted in interest expense of $59 million and $36 million in 2010, respectively. In addition, in 2011, Exelon recorded interest income and tax benefits of $46 million, net of tax including the impact on the manufacturer's deduction, due to the 2011 NDT fund special transfer tax deduction. The decrease in interest expense was partially offset by higher interest expense at Generation and ComEd due to higher outstanding debt balances. Exelon's results were also significantly affected by unrealized losses on NDT funds of $88 million in 2011 (compared to unrealized gains of $48 million in 2010) for Non-Regulatory Agreement Units as a result of unfavorable market performance.

Exelon's results for the nine months ended September 30, 2010 were favorably affected by certain prior year income tax-related matters. In 2010, Exelon recorded a $65 million (after-tax) charge to income tax expense as a result of health care legislation passed in March 2010 that includes a provision that reduces the deductibility of retiree prescription drug benefits for Federal income tax purposes. This amount was partially offset by a non-cash charge of $29 million (after-tax) recorded at Exelon in 2011 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, 2011, 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, 2011 were $743 million, or $1.12 per diluted share, compared with adjusted (non-GAAP) operating earnings of $739 million, or $1.11 per diluted share, for the same period in 2010. Exelon's adjusted (non-GAAP) operating earnings for the nine months ended September 30, 2011 were $2,219 million, or $3.34 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,057 million, or $3.10 per diluted share, for the same period in 2010. 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, 2011 as compared to the same periods in 2010:

	Three Months Ended September 30,			
	2011		2010	
(All amounts after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income	$ 601	$ 0.90	$ 845	$ 1.27
Illinois Settlement Legislation(a)	—	—	3	—
Mark-to-Market Impact of Economic Hedging Activities(b)	55	0.08	(99)	(0.14)
Unrealized (Gains) Losses Related to NDT Fund Investments(c)	76	0.12	(60)	(0.09)
Impairment of Certain Emission Allowances(d)	—	—	35	0.05
Retirement of Fossil Generating Units(e)	2	—	14	0.02
Asset Retirement Obligation(f)	16	0.02	—	—
Constellation Acquisition Costs(g)	11	0.02	—	—
Acquisition Costs(h)	5	0.01	1	—
Wolf Hollow acquisition(i)	(23)	(0.03)	—	—
Adjusted (non-GAAP) Operating Earnings	$ 743	$ 1.12	$ 739	$ 1.11

	Nine Months Ended September 30,			
	2011		2010	
(All amounts after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income	$1,889	$ 2.84	$2,039	$ 3.08
Illinois Settlement Legislation(a)	—	—	10	0.01
Mark-to-Market Impact of Economic Hedging Activities(b)	219	0.34	(166)	(0.25)
Unrealized (Gains) Losses Related to NDT Fund Investments(c)	46	0.07	(28)	(0.04)
Impairment of Certain Emission Allowances(d)	—	—	35	0.05
Retirement of Fossil Generating Units(e)	29	0.04	34	0.05
Asset Retirement Obligation(f)	16	0.02	—	—
Constellation Acquisition Costs(g)	26	0.04	—	—
Acquisition Costs(h)	5	0.01	1	—
Wolf Hollow acquisition(i)	(23)	(0.03)	—	—
City of Chicago Settlement with ComEd(j)	—	—	2	—
Non-Cash Remeasurement of Income Tax Uncertainties and Reassessment of State Deferred Income Taxes(k)	—	—	65	0.10
Non-Cash Charge Resulting From Health Care Legislation(l)	—	—	65	0.10
Non-Cash Charge Resulting From Illinois Tax Rate Change Legislation(m)	29	0.04	—	—
Recovery of Costs Resulting From Distribution Rate Case Order(n)	(17)	(0.03)	—	—
Adjusted (non-GAAP) Operating Earnings	$2,219	$ 3.34	$2,057	$ 3.10

(a) Reflects credits issued by Generation and ComEd for the three and nine months ended September 30, 2010, as a result of the Illinois Settlement Legislation (net of taxes of $2 million and $6 million, respectively). See Note 2 of the 2010 Form 10-K for additional detail related to Generation's and ComEd's rate relief commitments.

(b) Reflects the impact of (gains) losses for the three and nine months ended September 30, 2011 (net of taxes of $36 million and $144 million, respectively) and for the three and nine months ended September 30, 2010 (net of taxes of $(64) million and $(107) million, respectively) on Generation's economic hedging activities. See Note 6 of the Combined Notes to the Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(c) Reflects the impact of (gains) losses for the three and nine months ended September 30, 2011 (net of taxes of $141 million and $82 million, respectively) and for the three and nine months ended September 30, 2010 ($(112) million and $(46) million, respectively), on Generation's NDT fund investments for Non-Regulatory Agreement Units. See Note 9 of the Combined Notes to the Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(d) Reflects the impairment of certain emission allowances in the third quarter of 2010 as a result of declining market prices following the release of the EPA's proposed Transport Rule (net of taxes of $22 million). See Note 18 of the 2010 Form 10-K for additional information.

(e) Primarily reflects accelerated depreciation expense for the three and nine months ended September 30, 2011 (net of taxes of $2 million and $19 million, respectively) and for the three and nine months ended September 30, 2010 (net of taxes of $9 million and $22 million, respectively) associated with the planned retirement of four generating units, two of which were retired on May 31, 2011. Beginning June 1, 2011, reflects the net loss attributable to the remaining two units, which includes compensation for operating the units past their planned May 31, 2011 retirement date under a FERC-approved reliability-must-run rate schedule. See Note 11 of the Combined Notes to the Consolidated Financial Statements and "Results of Operations — Generation" for additional detail related to the generating unit retirements.

(f) Reflects the income statement impact for the three and nine months ended September 30, 2011 and 2010, respectively, related to the reduction in PECO's asset retirement obligations (net of taxes of $(1) million) and an increase in Generation's Zion's decommissioning obligation for spent nuclear fuel at Zion in 2011 (net of taxes of $11 million).

(g) Reflects certain costs incurred for the three and nine months ended September 30, 2011 associated with Exelon's proposed acquisition of Constellation (net of taxes of $7 million and $17 million, respectively). See Note 4 of the Combined Notes to the Consolidated Financial Statements for additional information.

(h) Reflects certain costs incurred for the nine months ended September 30, 2010 associated with Exelon's acquisitions of Exelon Wind (net of taxes of $1 million) and Antelope Valley (net of taxes of $3 million). See Note 4 of the Combined Notes to the Consolidated Financial Statements for additional information.

(i) 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). See Note 4 of the Combined Notes to the Consolidated Financial Statements for additional information.

(j) Reflects costs for the nine months ended September 30, 2010 associated with ComEd's 2007 settlement agreement with the City of Chicago (net of taxes of $1 million).

(k) Reflects the impacts of 2010 remeasurements of income tax uncertainties for the nine months ended September 30, 2010. See Note 8 of the Combined Notes to the Consolidated Financial Statements for additional detail.

(l) Reflects a non-cash charge to income taxes related to the passage of Federal health care legislation, which includes a provision that reduces the deductibility, for Federal income tax purposes, of retiree prescription drug benefits for Federal income tax purposes to the extent they are reimbursed under Medicare Part D. See Note 8 of the Combined Notes to the Consolidated Financial Statements for additional detail related to the impact of the health care legislation.

(m) 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 8 of the Combined Notes to the Consolidated Financial Statements for additional detail related to the impact of the Illinois tax rate change legislation.

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

Outlook for the Remainder of 2011 and Beyond

Acquisitions

Proposed Acquisition of Constellation Energy Company. On April 28, 2011, Exelon and Constellation Energy Group, Inc. (Constellation) announced that they signed an agreement and plan of merger to combine the two companies in a stock-for-stock transaction. Under the merger agreement, Constellation's shareholders will receive 0.930 shares of Exelon common stock in exchange for each share of Constellation common stock. Based on Exelon's closing share price on April 27, 2011, Constellation shareholders would receive $7.9 billion in total equity value. The resulting company will retain the Exelon name and be headquartered in Chicago.

The transaction must be approved by the shareholders of both Exelon and Constellation. Completion of the transaction is also conditioned upon approval by the FERC, NRC, Maryland Public Service Commission

(MDPSC), the New York Public Service Commission (NYPSC), the Public Utility Commission of Texas (PUCT), and other state and federal regulatory bodies. The companies have proposed to divest three Constellation generating stations located in PJM, which is the only market where there is a material overlap of generation owned by both companies. These stations, Brandon Shores and H.A. Wagner in Anne Arundel County, Md., and C.P. Crane in Baltimore County, Md., 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 the merged company, 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 the merged company will bid its units into the PJM markets. In addition, under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act), the transaction cannot be completed until Exelon has made required notifications and given certain information and materials to the FTC and/or the Antitrust Division of the DOJ and until specified waiting period requirements have expired. During the second quarter, Exelon and Constellation filed applications with FERC, the MDPSC, the NYPSC and the PUCT seeking approval of the transaction. Exelon and Constellation also filed an application with the NRC for indirect transfer of Constellation licenses and filed notifications with the FTC and DOJ in compliance with the requirements of the HSR Act. During the third quarter, Exelon and Constellation received approval of the transaction from the PUCT.

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 is disclosed and sought rescission of the proposed merger. During the third quarter, the parties to the suits reached an agreement in principle to settle the suits through additional disclosures to Constellation shareholders. The settlement is subject to court approval.

Through September 30, 2011, Exelon has incurred approximately $37 million of expense associated with the transaction, primarily related to fees incurred as part of the acquisition. Exelon currently estimates the total costs directly related to closing the transaction will be $144 million, which include financial advisor, consultant, legal and SEC registration fees. In addition, Exelon estimates approximately $500 million of additional integration costs, primarily to be incurred in 2012 and 2013. Such costs are expected to be partially offset by projected merger-related synergies in 2012 and fully offset in 2013 and beyond. As part of the application for approval of the merger by MDPSC, Exelon and Constellation have proposed a package of benefits to Baltimore Gas and Electric Company customers, the City of Baltimore and the State of Maryland, which will result in a direct investment in the state of Maryland of more than $250 million. Under the merger agreement, in the event Exelon or Constellation terminates the merger agreement to accept a superior proposal, or under certain other circumstances, Exelon or Constellation, as applicable, would be required to pay a termination fee of $800 million in the case of a termination fee payable by Exelon to Constellation or a termination fee of $200 million in the case of a termination fee payable by Constellation to Exelon. The acquisition is anticipated to be break-even to Exelon’s adjusted earnings in 2012 and is expected to be accretive to earnings in 2013. The companies anticipate closing the transaction in early 2012.

Acquisition of Antelope Valley Solar Ranch One. On September 30, 2011, Generation announced its acquisition of Antelope Valley Solar Ranch One (Antelope Valley), a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, which developed and will build, operate, and maintain the project. Construction has started, with the first portion of the site expected to come online in late 2012 and full operation planned for late 2013. When fully operational, Antelope Valley will be one of the largest PV solar projects in the world, with approximately 3.8 million solar panels generating enough clean, renewable electricity to power the equivalent of 75,000 average homes per year. The acquisition builds on the Exelon commitment to clean energy as part of Exelon 2020, a business and environmental strategy to eliminate the equivalent of Exelon’s 2001 carbon footprint. The project has a 25-year PPA, approved by the

California Public Utilities Commission, with Pacific Gas & Electric Company for the full output of the plant. Exelon expects to invest up to $713 million in equity in the project through 2013. The DOE's Loan Programs Office issued a loan guarantee of up to $646 million to support project financing for Antelope Valley. Exelon expects the total investment of up to $1.36 billion to be accretive to earnings beginning in 2013 and cash flow accretive starting in 2013. The project is value accretive, and will have stable earnings and cash flow profiles due to the PPA.

Acquisition of Wolf Hollow Generating Station. On August 24, 2011, Generation completed the acquisition of the equity interest of Wolf Hollow, LLC (Wolf Hollow), a combined-cycle natural gas-fired power plant in north Texas, pursuant to which Generation added 720 MWs of capacity within the ERCOT power market. The acquisition builds on the Exelon commitment to clean energy as part of Exelon 2020. Generation recognized a $36 million bargain purchase gain (i.e., negative goodwill) as part of the transaction. The gain was included within other, net in Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income. In connection with the acquisition, Generation terminated and settled its long-term PPA with Wolf Hollow; resulting in a gain of approximately $6 million, which is included within Operating Revenues (Other Revenue) in Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income.

Acquisition of John Deere Renewables. In December 2010, Generation acquired all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind), a leading operator and developer of wind power, for approximately $893 million in cash. Generation acquired 735 MWs of installed, operating wind capacity located in eight states. Approximately 75% of the operating portfolio's expected output is already sold under long-term power purchase arrangements. Additionally, Generation will pay up to $40 million related to three projects with a capacity of 230 MWs which are currently in advanced stages of development, contingent upon meeting certain contractual commitments related to the commencement of construction of each project. This contingent consideration was valued at $32 million of which approximately $16 million was paid during third quarter of 2011. As a result, total consideration recorded for the Exelon Wind acquisition was $925 million. The acquisition currently provides incremental earnings, provides cash flows starting in 2013 and is a key part of Exelon 2020.

Recent Natural Disasters, including the Japan Earthquake and Tsunami

Generation's fleet of nuclear power plants could be impacted by natural disasters, such as seismic activity, more frequent and more extreme weather events, changes in temperature and precipitation patterns, sea level rise and other related phenomena. Generation continuously assesses the impact such activity has, or could have, on its nuclear fleet to mitigate risks to public safety and plant operations. An example of such an event was the 9.0 magnitude earthquake and ensuing tsunami experienced by Japan on March 11, 2011, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co. Also, on August 23, 2011, Generation's fleet of nuclear plants throughout the Mid-Atlantic region of the United States experienced a 5.8 magnitude earthquake and continued to operate with no impact. Finally, during the third quarter of 2011, the Mid-Atlantic region of the United States experienced flooding associated with Hurricane Irene and tropical storm Lee. These events increase the risk to Generation that the NRC (Commission) or other regulatory or legislative bodies may change the laws or regulations governing, among other things, operations, maintenance, licensed lives, decommissioning, SNF storage, insurance, emergency planning, security and environmental and radiological aspects.

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. Prior to the earthquake and tsunami in Japan, the NRC and licensees had been evaluating seismic risk in relation to the design basis and whether additional regulatory action was required. Following the March 11, 2011 events, interest in seismic risk intensified. On September 1, 2011, the NRC issued a draft generic letter that will, if finalized, require Generation to use a specified methodology to evaluate each of its plants for the current risk presented by seismic events and provide information to the NRC so that the NRC can determine whether additional regulatory action is required.

The NRC received petitions from various individuals and citizen groups requesting actions be taken in response to the events in Japan. A consortium of various citizen groups filed a petition with the NRC requesting that it act under its supervisory powers to suspend all reactor licensing decisions and related rulemaking decisions pending the NRC's investigation of the events at Fukushima Daiichi. On September 9, 2011, the Commission denied the request. Also, various NRC petitions have been filed seeking suspension of all Boiling Water Reactor (BWR) Mark I operating licenses or other enforcement action until certain specified conditions are met. Another petition requests that the NRC take enforcement action by requiring all operating licensees of BWR Mark I and Mark II containments to demonstrate compliance with current regulatory requirements. These petitions could affect Dresden, Quad Cities, Oyster Creek and Peach Bottom stations (Mark I containment designs) and LaSalle and Limerick stations (Mark II containment designs). Generation does not believe the petitions will be successful. On May 18, 2011, the U.S. Court of Appeals of the Third Circuit upheld the NRC's decision to grant Oyster Creek a 20-year license extension and specifically stated that the events at the Fukushima Daiichi plant do not affect the decision to grant the license extension.

Since the events in Japan took place, Generation has continued to work with regulators and nuclear industry organizations to understand the events in Japan and apply lessons learned. The nuclear industry is already taking specific steps to respond. Generation has completed actions requested by the Institute of Nuclear Power Operations (INPO), which included tests that verified its emergency equipment is available and functional, walk-downs on its procedures related to critical safety equipment, confirmation of event response procedures and readiness to protect the spent fuel pool, and verification of current qualifications of operators and support staff needed to implement the procedures. Generation is currently working on 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.

On July 12, 2011, the NRC Near-Term Task Force on the Fukushima Daiichi Accident (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 report is the first step in a systematic review that the NRC is conducting. 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 report includes recommendations to the NRC in three primary areas: 1) the overall structure and philosophy of the NRC's regulatory framework; 2) specific design requirements for the nuclear units; and 3) emergency preparedness. On August 19, 2011, the NRC directed the NRC staff to, among other things, identify those Task Force recommendations to be taken in the near term, prioritize and propose a schedule for all of the recommendations, propose regulatory actions to implement the recommendations, and identify additional recommendations. The Commission specifically called out the Task Force recommendation pertaining to the regulatory framework as being on an independent track for consideration over an eighteen month period.

On September 9, 2011, the NRC staff issued its report identifying seven Task Force recommendations to be taken in the near term or "without unnecessary delay." The seven near term recommendations cover seismic and flooding risks, coping with extended loss of power in a station blackout, protecting and increasing the amount of backup equipment, reliable hardened vents for Mark I containment, and enhancing procedures to address severe accidents and emergency planning. On October 3, 2011, the NRC staff issued its recommendations for prioritizing and implementing the near term and remaining Task Force recommendations and an implementation schedule. Of note, the NRC staff confirmed in both the September 9, 2011 and October 3, 2011 reports the Task

Force's conclusions that none of the findings or recommendations arising from the Task Force review presented an imminent risk to public health and safety. The NRC staff evaluated the potential and relative safety enhancements to be realized by each recommendation and, based on that evaluation, classified the recommendations as falling in three tiers: Tier 1, reflecting the near term recommendations to be initiated without unnecessary delay; Tier 2, reflecting recommendations to be deferred pending receipt of additional information, completion of Tier 1 activities, or the availability of resources; and Tier 3, reflecting recommendations to be deferred pending an additional nine month review by the NRC staff. With respect to the near term recommendations falling in Tier 1, the NRC staff added in the October 3, 2011 report recommendations for reliable hardened vents for Mark II containment and enhancements to spent fuel instrumentation as additional near term actions. As instructed by the Commission, the NRC staff also identified additional issues not considered by the Task Force that may, in the staff's assessment, warrant regulatory action. Among the additional issues identified is the transfer of spent fuel to dry cask storage. The staff committed to provide an update on its evaluation of the additional issues within nine months. For each of the recommendations and additional issues, the NRC staff's proposed schedule provides for stakeholder input prior to taking regulatory action.

On October 20, 2011, the NRC published the Commission's votes and staff requirements memorandum approving the staff's September 9, 2011 proposed actions to implement seven Task Force recommendations as near term actions, subject to a number of conditions. Specifically, the Commission encouraged the staff to create requirements based on a performance-based system which allows for flexible approaches and the ability to address a diverse range of site-specific circumstances and conditions and "strive to complete and implement the lessons learned from the Fukushima accident within five years — by 2016." In addition, the Commission is scheduled in the near term to vote on the NRC staff's October 3, 2011 report proposing a prioritization and implementation plan for the near term and remaining recommendations and issue instructions to the NRC staff for carrying out the decision of the Commission.

Generation is assessing the impacts of the NRC staff's evaluations and the Commission's approval of the recommendations for near term actions, both from an operational and a financial impact standpoint. Until the Commission votes on the NRC staff's proposal for prioritizing and implementing the Task Force recommendations and the specific requirements 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. However, Generation will continue to engage in nuclear industry assessments and actions.

The results of regulatory or political actions associated with the response to the events in Japan and the Task Force report could include a substantial increase in Generation's capital expenditures and operating costs; shortened economic lives for one or more nuclear generating units, resulting in accelerated depreciation charges; impairment of nuclear generating facilities and/or nuclear fuel inventory; or a change in timing of and/or approach to decommissioning activities, which could increase amounts or accelerate the timing of decommissioning expenditures. In addition, the effect of these changes could cause a downgrade of Exelon and Generation's credit ratings to below investment grade, resulting in requirements for substantial amounts of collateral and increased borrowing costs for Generation.

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. However, as noted above, the NRC staff identified the transfer of spent fuel to dry cask storage as an additional issue to be evaluated by the NRC staff over a nine month period. The facts surrounding what happened at the Fukushima Daiichi Nuclear Power Station, including the nature and extent of damages, the underlying causes of the situation, and the degree to which these factors apply to Generation's nuclear generating facilities, are still under investigation, and will be for some time. Although the NRC staff's September 9, 2011 and October 3, 2011 reports to the Commission and the Commission's approval of the near term recommendations and instructions to the NRC staff provide clarity with respect to issues that will be subject to regulatory review and action, the nature and degree of actions that will be required of Generation are still unknown and will be determined through the regulatory process after allowing for stakeholder input. As a result, Exelon and Generation are unable to conclude, at this time, to what extent any actions to comply with the requirements will impact their future results of operations, financial positions and cash flows. See the 2010 Form 10-K, Item 1A. Risk Factors, for further discussion of the risk factors.

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

Economic and Market Conditions

Exelon has exposure to various market and financial risks, including the risk of price fluctuations in the wholesale 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 nuclear power plants can command, (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 Cross-State Air Pollution Rule (CSAPR) and the New Jersey capacity legislation. See *Environmental Matters* and *Regulatory and Legislative Matters* sections below for further detail on CSAPR and New Jersey capacity legislation, respectively.

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 power prices, which results in a reduction in Exelon's revenues.

The market price for electricity is also affected by changes in the demand for electricity. Poor economic conditions, milder than normal weather and the growth of energy efficiency and demand response programs can depress demand. The result is that higher-cost generating resources do not run as frequently, putting downward pressure on market prices for electricity and/or capacity. The continued sluggish economy in the United States has led to slower growth of demand for electricity. Based on year to date load performance at September 30 and expectations for the fourth quarter, ComEd and PECO are projecting a slight decline in load demand for 2011 compared to 2010.

In addition, the Registrants have exposure to worldwide financial markets, including Europe. 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, 2011, approximately 35%, or $2.7 billion, of the Registrants' available credit facilities were with European banks. The credit facilities include $7.7 billion in aggregate total commitments of which $6.9 billion was available as of September 30, 2011. There were no borrowings under the Registrants' credit facilities as of September 30, 2011. See Note 7 of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

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. Although Exelon's hedging policies have helped protect Exelon's earnings as wholesale market prices have declined, sustained increases in natural gas supply and reserve levels, or a continued slow recovery of the economy, could result in a prolonged depression of or further decline in commodity prices and in long-term sluggish growth in demand.

Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for the remainder of 2011 and 2012. 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. Generation currently hedges commodity risk on a ratable basis over the three years leading to the spot market. As of September 30, 2011, the percentage of expected generation hedged was 97%-100%, 85%-88%, and 56%-59% for the remainder of 2011, 2012 and 2013, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include cash flow hedges, other derivatives and certain non-derivative contracts including sales to ComEd and PECO 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. The expiration of the PPA with PECO at the end of 2010 has resulted in increases in margins earned by Generation in 2011 for the portion of Generation's electricity portfolio previously sold to PECO under the PPA; however the ultimate impact of entering into new power supply contracts under Generation's three-year ratable hedging program to replace the PPA will depend on a number of factors, including future wholesale market prices, capacity markets, energy demand and the effects of any new applicable Pennsylvania laws and or rules and regulations promulgated by the PAPUC.

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 2011 through 2015 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position. Generation uses long-term contracts and financial instruments such as over-the-counter and exchange-traded instruments to mitigate price risk associated with certain commodity price exposures. Both ComEd and PECO 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. During 2009, Generation announced a series of planned power uprates across its nuclear fleet that would result in between 1,300 and 1,500 MWs of additional generation capacity within eight years at a total investment of approximately $3.65 billion in overnight cost, as measured in 2010 dollars. Overnight costs do not include financing costs or cost escalation. As part of periodic reviews of the continued economic viability of the projects, conducted in the second quarter of 2011, the planned increases have been revised to between 1,175 and 1,300 MWs at an overnight cost of approximately $3.30 billion in 2011 dollars primarily due to the deletion of the Three Mile Island extended power uprate from the plan due to low economic evaluation results. Using proven technologies, the projects take advantage of new production and measurement technologies, new materials and learning from a half-century of nuclear power operations. Uprate projects, representing approximately 70% of the planned uprate MWs, are 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 additional projects across Generation's nuclear fleet beginning later in 2011 and ending in 2017. At 1,300 nuclear-generated MWs, the uprates would displace 6 million metric tons of carbon emissions annually that would otherwise come from burning fossil fuels. The uprates are being undertaken pursuant to an organized, strategically sequenced implementation plan. The implementation effort includes a periodic review and refinement of the project in light of changing market conditions. The amount of expenditures to implement the plan ultimately will depend on economic and policy developments, and will be made on a project-by-project basis in accordance with Exelon's normal project evaluation standards. The ability to implement several projects requires the successful resolution of various technical issues. The resolution of these issues may affect the timing and amount of the power increases associated with the power uprate initiative. Through September 30, 2011, Generation has added 189 MWs of nuclear generation through its uprate program, with another 11 MWs scheduled to be added during the remainder of 2011.

Transmission Development Project. Exelon, Electric Transmission America, LLC (ETA) and AEP Transmission Holding Company, LLC (AEP) are working collaboratively to develop a 420-mile extra high-voltage transmission project from the western Ohio border through Indiana to the northern portion of Illinois. Referred to as the Reliability Interregional Transmission Extension (RITE) Line project, the project is expected to strengthen the high-voltage transmission system and improve overall system reliability. RITELine Illinois, LLC (RITELine Illinois) and RITELine Indiana, LLC (RITELine Indiana) have been formed as project companies to develop and own the project. RITELine Illinois will own the transmission assets located in Illinois and is owned 75% by ComEd and 25% by RITELine Transmission Development Company, LLC (RTD). RITELine Indiana will own the transmission assets located in Indiana and is owned by ETA (37.5%), AEP (37.5%) and RTD (25%). Exelon Transmission Company, LLC and ETA each own 50% of RTD. The total cost of the RITE Line project is expected to be approximately $1.6 billion, with the Illinois portion of the line expected to cost approximately $1.2 billion. The ultimate cost of the line will depend on a number of factors, including RTO requirements, state siting requirements, routing of the line, and equipment and commodity costs. The project will be built in stages over three to four years, likely between 2015 and 2018, and is subject to FERC, PJM and state approvals. Significant funding for this project is not expected to occur until 2014, with most of the funding expected in 2015-2017.

On July 18, 2011, RITELine Illinois and RITELine Indiana filed at FERC for incentive rates and a formula rate for the RITE Line project. On October 14, 2011, FERC issued an order on the incentive and formula rate filing. The order grants a base rate of return on common equity of 9.93%, plus a 50 basis point adder for the project being in an RTO and a 100 basis point adder for the risks and challenges of the project, resulting in a total rate of return on common equity of 11.43%. The order grants a hypothetical capital structure of 45% debt and 55% equity until any part of the project enters commercial operations. The order also grants 100% recovery for construction work in progress, 100% recovery for abandonment, if the line is abandoned through no fault of the RITELine developers, and the ability to treat pre-construction costs as a regulatory asset. All incentives, including the abandonment incentive, are contingent on inclusion of the project in the PJM RTEP. The order is subject to petitions for rehearing.

Advanced Metering Infrastructure. In April 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan under which PECO will deploy 600,000 smart meters within three years and deploy smart meters to all of its electric customers over the next 10 years. Also in April 2010, PECO entered into a Financial Assistance Agreement with the DOE for a $200 million award for SGIG funds under the ARRA. In total, through 2020, PECO plans to spend up to a total of $650 million on its smart grid and smart meter infrastructure. The $200 million SGIG from the DOE is being used to reduce the impact of these investments on PECO ratepayers.

On April 15, 2011, the PAPUC issued the order approving the joint petition for partial settlement of the initial dynamic pricing and customer acceptance plan and ruled that the administrative costs be recovered from default service customers through the GSA. PECO plans to file for approval of a universal meter deployment plan for its remaining customers in 2012.

In October 2009, the ICC approved ComEd's proposed AMI pilot program, with minor modifications, and recovery of substantially all program costs from customers. The one-year program was operational in June 2010. As of September 30, 2011, ComEd had spent $77 million associated with the pilot program. The AMI pilot program allows ComEd to study the costs and benefits related to automated metering and to develop the cost estimate of potential full system-wide implementation of AMI. In addition, the program allows customers the ability to manage energy use, improve energy efficiency and lower energy bills. Due to an adverse September 30, 2010 Illinois Appellate Court decision, ComEd faced certain cost recovery issues in connection with the pilot program. The ICC order in ComEd's 2010 Rate Case subsequently approved base rate recovery of the investment and pilot program costs. See Regulatory and Legislative Matters below and Note 3 of the Combined Notes to Consolidated Financial Statements for information on cost recovery issues related to ComEd's AMI pilot program.

Liquidity and Cost Management

Pension Plan Funding. As a result of accelerated cash benefits associated with the Tax Relief Act of 2010, Exelon contributed $2.1 billion to its pension plans in January 2011, representing substantially all currently planned 2011 qualified pension contributions. Exelon's funding of these contributions included $500 million from cash from operations, $750 million from the tax benefits of making the pension contributions and $850 million associated with the accelerated cash tax benefits from the 100% bonus depreciation provision enacted as part of the Tax Relief Act of 2010. Exelon expects the $2.1 billion contribution, along with other factors, will increase the pension funded status from 71% at December 31, 2010 to 83% at December 31, 2011, subject to actual 2011 asset returns and final actuarial valuations. The $2.1 billion pension contribution also decreased 2011 pension costs.

Financing Activities. On January 18, 2011, ComEd issued $600 million of 1.625% First Mortgage Bonds due January 15, 2014. The net proceeds of the bonds were used as an interim source of liquidity for the January 2011 contribution to Exelon-sponsored pension plans in which ComEd participates. ComEd anticipates receiving tax refunds as a result of both the pension contribution and the Tax Relief Act of 2010 allowing for 100% bonus depreciation deductions in 2011 and 2012. As a result, the immediate use of the net proceeds to fund the planned contribution will allow those future cash receipts to be available to fund capital investment and for general corporate purposes.

On September 7, 2011, ComEd issued $250 million of 1.95% First Mortgage Bonds due September 1, 2016 and $350 million of 3.40% First Mortgage Bonds due September 1, 2021. A portion of the net proceeds of the bonds was used to refinance $191 million of ComEd's variable rate tax-exempt bonds on October 12, 2011. The remainder of the net proceeds will be used to refinance $345 million of 5.40% First Mortgage bonds due December 15, 2011 and to fund other general corporate purposes.

Credit Facilities. On March 23, 2011, Exelon Corporate, Generation and PECO replaced their unsecured revolving credit facilities with new facilities with aggregate bank commitments of $500 million, $5.3 billion and $600 million, respectively. Although the covenants are largely the same as the prior facilities, the new facilities have higher borrowing costs, reflecting current market pricing. See Note 7 of the Combined Notes to Consolidated Financial Statements for further information regarding those costs.

ComEd's $1.0 billion unsecured revolving credit facility expires on March 25, 2013 unless extended in accordance with terms. ComEd plans to renew or replace the credit facility in 2012. See Note 7 of the Combined Notes to Consolidated Financial Statements for further information regarding the credit facility terms.

On October 21, 2011, 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. See Note 7 of the Combined Notes to Consolidated Financial Statements for further information regarding the credit facilities.

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 make itself more effective, efficient and innovative. Exelon is committed to maintaining a cost control focus and continues to analyze cost trends to identify future cost savings opportunities and implement more planning and performance-measurement tools to allow it to better identify areas for sustainable productivity improvements and cost reductions across the Registrants.

Environmental Matters

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

Environmental Legislative and Regulatory Developments

Exelon supports the promulgation of environmental regulation by the U.S. EPA, including air, water and waste controls for electric generating units. See discussion below for further details. The air and waste regulations will have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and will likely result in the retirement of older, marginal facilities. Due to its low emission generation portfolio, Generation will not be significantly directly affected by these regulations, representing a competitive advantage for Generation relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. House of Representatives 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 expected to be 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). The U.S. EPA has announced that it will complete a review of NAAQS in the 2011-2012 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 a final rule known as CSAPR. The CSAPR requires 27 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. Upon preliminary review, it is expected that implementation of the CSPAR will modestly increase power prices over the long term, which would result in a net benefit to Generation's results of operations and cash flows. Several entities have 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 believes that the CSAPR is a valid exercise of the U.S. EPA's authority and discretion under the CAA. Exelon has received permission from the Court to intervene in support of the rule and in opposition to a stay of the rule.

On October 14, 2011, the 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 March 16, 2011, the U.S. EPA issued a proposed rule setting national emission standards for HAPs from coal- and oil-fired electric generating facilities (the Toxics Rule). The Toxics Rule would require 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 Toxics Rule may need to upgrade existing controls or add new controls to comply. Exelon, along with the other co-owners of Conemaugh Generating Station, are evaluating controls needed to comply with the Toxics Rule. EPA's proposed standards will require oil units to achieve high removal rates of metals. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies, or retire the units. The ultimate nature and extent of future required regulatory controls on HAP emissions at electric generation power plants will not be determined until the Toxics Rule is finalized by the EPA in December 2011.

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.

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 during the 111th Congress, 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 EPA for further consideration and revision. On March 28, 2011, the 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.

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 waste (CCW) would be regulated for the first time under the RCRA. The U.S. EPA is considering several options, including classification of CCW either as a hazardous or non-hazardous waste. Under either option, the U.S. EPA's intention is the ultimate elimination of surface impoundments as a waste treatment process. For plants affected by the proposed rules, this would result in significant capital expenditures and variable operating and maintenance expenditures to convert to dry handling and disposal systems and installation of new waste water treatment facilities. Generation anticipates that the only plants in which it has an ownership interest that would be affected by proposed rules would be Keystone and Conemaugh. As a result, Exelon does not currently expect the adoption of the rules as proposed to have a significant impact on its future capital spending requirements and operating costs. The U.S. EPA has not announced a target date for finalization of the CCW rules.

See Note 13 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

Appeal of 2007 Illinois Electric Distribution Rate Case. On September 30, 2010, the Illinois Appellate Court (Court) issued a decision in the appeals related to the ICC's order in ComEd's 2007 electric distribution rate case (2007 Rate Case). That decision ruled against ComEd on the treatment of post-test year accumulated depreciation and the recovery of costs for an AMI/Customer Applications pilot program via a rider (Rider SMP). On January 25, 2011, ComEd filed a Petition for Leave to Appeal to the Illinois Supreme Court that was denied on March 30 2011. The ICC has initiated a proceeding on remand. ComEd expects that the ICC will issue a final order in early 2012. ComEd filed testimony that no refunds should be required in this proceeding and in the event of any refund, the maximum refund should be $30 million. In September 2011, intervenors filed testimony that ComEd should refund approximately $37 million, including interest, to customers related to post-test year accumulated depreciation. As of September 30, 2011, ComEd has recognized for accounting purposes its best estimate of any refund obligation, subject to true-up when the ICC issues a final order. ComEd does not believe any of its other riders are affected by the Court's ruling. See Note 3 of the Combined Notes to Consolidated Financial Statements for further details related to the Court's order.

2010 Illinois Electric Distribution Rate Case. On May 24, 2011, the ICC issued an order in ComEd's 2010 electric delivery services rate case. ComEd requested an increase in the annual revenue requirement to allow ComEd to recover the costs of substantial investments made in its distribution system since its last rate filing in 2007. The requested increase also reflected increased costs, most notably pension and other postretirement employee benefits, since ComEd's rates were last determined.

The ICC order, which became effective on June 1, 2011, approved a $143 million increase to ComEd's annual delivery services revenue requirement, which is approximately 42% of the $343 million requested by ComEd in its reply brief on February 23, 2011. The approved rate of return on common equity is 10.50%. As a result of the order, ComEd recorded a one-time net benefit of approximately $58 million that includes the reestablishment of previously expensed plant balances, the establishment of new regulatory assets, and the reversal of certain reserves. The benefit is reflected as an increase to operating revenues and a reduction in operating and maintenance expense and income tax expense for the nine months ended September 30, 2011. The order has been appealed to the Court by several parties, including ComEd. ComEd cannot predict the results of these appeals. See Note 3 of the Combined Notes to Consolidated Financial Statements for further details related to the 2010 Rate Case.

Legislation to Modernize Electric Utility Infrastructure and to Update Illinois Ratemaking Process. ComEd and Ameren are working with state legislators to enact legislation that would modernize Illinois' electric grid. The legislation includes a policy-based approach that would provide a more predictable ratemaking system and would enable utilities to modernize the electric grid and set the stage for fostering economic development while creating and retaining jobs. Many other states are changing or are considering changes to the way they regulate utilities in order to improve the predictability of the ratemaking process.

The Illinois Energy Infrastructure Modernization Act (SB 1652), a prior version of which was originally introduced as HB 14, was passed by the Illinois General Assembly on May 31, 2011. SB 1652 would apply to electric utilities in Illinois on an opt-in basis. SB 1652 provides greater certainty related to the recovery of costs by a utility through a pre-established formula, which would still allow the ICC and interveners the opportunity to review the prudence and reasonableness of costs. If the legislation were to be enacted, upon approval from ComEd's Board of Directors, ComEd would anticipate filing annual electric distribution formula rate cases and investing an additional $2.6 billion (potentially up to $3 billion) in capital expenditures over the next ten years to modernize its system and implement smart grid technology, including improvements to cyber security. These investments would be incremental to ComEd's historical level of capital expenditures. SB 1652 also contains a provision for the IPA to complete a procurement event for energy requirements for the June 2013 through May 2017 period. If SB 1652 is enacted, the procurement event must take place within 120 days of the effective date of the legislation.

On September 12, 2011, the Governor vetoed the bill. The legislation will now go back to the General Assembly, which may override the veto with a super-majority vote during the fourth quarter. If approved in its current form and upon approval from ComEd's Board of Directors, ComEd expects that it would begin to achieve closer to its allowed return on equity, which would have a material positive impact on ComEd's net income as early as 2011. ComEd's commitments in the bill associated with incremental capital expenditures would result in significant cash outflows beginning in 2012. ComEd cannot predict the eventual outcome of SB 1652 resulting from subsequent actions taken by the Illinois General Assembly. To the extent that the bill is not enacted as currently written or in a comparable form, ComEd will seek alternative methods to achieve reasonable earned returns on equity, which would include additional electric distribution rate case filings with the ICC.

2011 Pennsylvania Electric and Natural Gas Rates. On December 16, 2010, the PAPUC approved the settlement of PECO's electric distribution rate case for an increase of $225 million in annual service revenue, which is approximately 71% of the $316 million originally requested. The natural gas distribution rate case settlement reflects an increase of approximately $20 million in annual service revenue, which is approximately 46% of the $44 million originally requested. The approved electric and natural gas distribution rates became effective on January 1, 2011.

See Note 3 of the Combined Notes to Consolidated Financial Statements for further details related to PECO's rate case settlements.

Financial Reform Legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted into law on July 21, 2010. This financial reform legislation includes a provision that requires over-the-counter derivative transactions to be executed through an exchange or centrally cleared. The legislation provides an exemption from mandatory clearing requirements for transactions that are used to hedge commercial risk like those utilized by Generation. At the same time, the legislation includes provisions under which the Commodity Futures Trading Commission (CFTC) may impose collateral requirements for transactions, including those that are used to hedge commercial risk. However, during drafting of the legislation, members of Congress issued a public letter stating that it was not their intention to impose margin and collateral requirements on counterparties that utilize transactions to hedge commercial risk. Final rules on major provisions in the legislation, including new margin requirements, will be established through rulemakings and will not take effect until 12 months after the date of enactment. On July 14, 2011, the CFTC issued an order providing temporary relief to those entities engaging in swap transactions from certain provisions that would otherwise have applied as of July 16, 2011 until the CFTC completes the rulemakings specified in the order. This order will expire upon the earlier of the effective date of final rules or December 31, 2011. If deemed a swap dealer, Generation would be required to execute over-the-counter derivative transactions, except those with qualifying end-users that are used to hedge commercial risk, through an exchange or central clearinghouse subject to margin requirements; conversely, if deemed a qualifying end-user, Generation could elect not to clear such transactions. Although Exelon and Generation believe a swap dealer designation is unlikely, a substantial shift from over-the-counter sales to exchange cleared sales is estimated to require approximately $1 billion of additional collateral. Generation has adequate credit facilities and flexibility in its hedging program to accommodate these legislative or market changes. 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 Jersey Capacity Legislation. New Jersey Senate Bill 2381 was enacted into law on January 28, 2011. This legislation established a long-term capacity pilot program under which the New Jersey Board of Public Utilities (NJBPU) administered an RFP process in the first quarter of 2011 to solicit offers for capacity agreements with mid-merit and/or base-load generation constructed after the effective date of the bill. In the first quarter of 2011, the NJBPU approved the RFP results, which included capacity agreements for a term of up to 15 years for 2,000 MWs. The NJBPU has initiated a proceeding to examine whether additional capacity is needed. A final staff report is due to be issued before the end of the year.

The selected generators from the RFP process are required to bid in and clear the PJM RPM auction, likely causing them to bid in the PJM RPM auction at zero. Under the pilot program, generators are paid based on the RFP contract price; therefore, any difference between the RPM clearing price and the RFP contract price is either ultimately recovered from or refunded to New Jersey electric customers. This state-required customer subsidy for generation capacity is expected to artificially suppress capacity prices within the Mid-Atlantic region in future auctions, which could adversely affect Generation's results of operations and cash flows. Other states could seek to establish similar programs, which could substantially impair Exelon's market driven position.

PJM's capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. See Note 3 of the Combined Notes to Consolidated Financial Statements for further details related to PJM's MOPR.

Tax Matters

Accounting for Electric Transmission and Distribution Property Repairs. On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for repair costs associated with electric transmission and distribution property. For the three and nine months ended September 30, 2011, the adoption of the safe harbor resulted in a $26 million reduction to income tax expense at PECO, while Generation incurred additional income tax expense in the amount of $23 million due to a decrease in its manufacturer's deduction. For Exelon, the adoption had a minimal effect on consolidated earnings. In addition, the adoption of the safe harbor will result in a cash tax benefit at Exelon, ComEd and PECO in the amount of approximately $300 million, $250 million and $95 million, respectively, partially offset by a cash tax detriment at Generation in the amount of $28 million. See Notes 3 and 8 of the Combined Notes to Consolidated Financial Statements for additional information on the electric transmission and distribution property repairs.

Nuclear Decommissioning Trust Fund Special Transfer Tax Deduction. During 2008, Generation benefited from a provision in the Energy Policy Act of 2005 which allowed companies an income tax deduction for a "special transfer" of funds from a non-tax qualified NDT fund to a qualified NDT fund. As a result of temporary guidance published by the U.S. Department of Treasury, Generation completed a special transfer in the first quarter of 2008 for tax year 2008. In December 2010, the U.S. Department of Treasury issued final regulations under IRC Section 468A. The final regulations included a transitional relief provision which allowed taxpayers to request permission from the IRS to designate a taxable year, as far back as 2006, during which the special transfer will be deemed to have occurred. Exelon determined, and is confirming with the IRS through the ruling process, that this provision allows a majority of Generation's 2008 special transfer tax deduction to be claimed in the 2006 tax year and the remaining portions claimed ratably in taxable years 2007 and 2008. On February 18, 2011, in order to preserve both the ability to designate the special transfer from 2008 to an earlier taxable year and the ability to complete future additional special transfers, Exelon filed ruling requests with the IRS. Exelon has received its first favorable ruling from the IRS in the second quarter of 2011, along with several additional favorable rulings during July 2011, and expects that the remaining rulings to be received will be favorable as well. As a result, Exelon recorded an interest and tax benefit of $43 million, net of tax including the impact on the manufacturer's deduction, in the second quarter of 2011 related to the special transfer completed in 2008. In addition, during the third quarter, Exelon completed additional special transfers resulting in an additional interest benefit of $3 million (after tax).

Illinois State Income Tax Legislation. The Taxpayer Accountability and Budget Stabilization Act (SB 2505), enacted into law in Illinois on January 13, 2011, increases the corporate tax rate in Illinois from 7.3% to 9.5% for tax years 2011-2014, provides for a reduction in the rate from 9.5% to 7.75% for tax years 2015-2024 and further reduces the rate from 7.75% to 7.3% for tax years 2025 and thereafter. Pursuant to the rate change, Exelon reevaluated its deferred state income taxes during the first quarter of 2011. Illinois' corporate income tax rate changes resulted in a charge to state deferred taxes (net of Federal taxes) during the first quarter of 2011 of $7 million, $11 million and $4 million for Exelon, Generation and ComEd, respectively. Exelon's and ComEd's charge is net of a regulatory asset of $15 million.

In 2011, the income tax rate change is expected to increase Exelon's Illinois income tax provision (net of federal taxes) by approximately $5 million, of which $11 million and $4 million of additional tax relates to Exelon Corporate and Generation, respectively, and a $10 million benefit for ComEd. The 2011 tax benefit at ComEd reflects the impact of a 2011 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010 and the electric transmission and distribution property repairs discussed in Note 8 of the Combined Notes to Consolidated Financial Statements.

Plant Retirements

Oyster Creek. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019, in view of the costs that might have been associated with the installation of closed-cycle cooling had operations continued to the end of its current NRC license in 2029. During the first quarter of 2011, Generation made employee retention payments of approximately $14 million that are expected to increase operating expenses by approximately $3 million (pre-tax) in each of the years 2011 through 2015.

Eddystone and Cromby. 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 that date 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; however, Cromby Unit 2 will retire on December 31, 2011 and Eddystone Unit 2 will retire on May 31, 2012. On May 31, 2011, Cromby Generating Station (Cromby) Unit 1 and Eddystone Generating Station (Eddystone) Unit 1 were retired; however, Cromby Unit 2 will retire on December 31, 2011 and Eddystone Unit 2 on June 1, 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 and Cromby Unit 2 is approximately $6 million and $2 million, respectively. In addition, Generation is recovering variable costs including fuel, emissions costs, chemicals, auxiliary power and for project investment costs during the reliability-must-run period. Eddystone Unit 2 and Cromby Unit 2 began operating under the reliability-must-run agreement effective June 1, 2011.

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 Exelon's 2010 Annual Report on 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, 2011, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2010.

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Results of Operations

Net Income (Loss) by Registrant

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Favorable (Unfavorable) Variance
Generation	$ 386	$ 605	$ (219)	$ 1,325	$ 1,548	$ (223)
ComEd	112	121	(9)	295	246	49
PECO	105	127	(22)	314	303	11
Other(a)	(2)	(8)	6	(45)	(58)	13
Exelon	$ 601	$ 845	$ (244)	$ 1,889	$ 2,039	$ (150)

(a) Other primarily includes corporate operations, BSC and intersegment eliminations.

Results of Operations — Generation

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Favorable (Unfavorable) Variance
Operating revenues	$ 2,862	$ 2,655	$ 207	$8,147	$ 7,428	$ 719
Purchased power and fuel expense	1,112	945	(167)	3,023	2,442	(581)
Revenue net of purchased power and fuel expense(a)	1,750	1,710	40	5,124	4,986	138
Other operating expenses						
Operating and maintenance	790	649	(141)	2,306	2,081	(225)
Depreciation and amortization	139	121	(18)	416	344	(72)
Taxes other than income	67	57	(10)	199	175	(24)
Total other operating expenses	996	827	(169)	2,921	2,600	(321)
Operating income	754	883	(129)	2,203	2,386	(183)
Other income and deductions						
Interest expense	(37)	(37)	—	(128)	(109)	(19)
Other, net	(164)	192	(356)	(12)	138	(150)
Total other income and deductions	(201)	155	(356)	(140)	29	(169)
Income before income taxes	553	1,038	(485)	2,063	2,415	(352)
Income taxes	167	433	266	738	867	129
Net income	$ 386	$ 605	$ (219)	$1,325	$ 1,548	$ (223)

(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, 2011 Compared to Three Months Ended September 30, 2010. Generation's net income decreased compared to the same period in 2010 primarily due to unfavorable NDT fund performance in 2011, mark-to-market losses on economic hedging activities, unfavorable capacity pricing, higher nuclear fuel costs and higher operating and maintenance expense. Higher operating and maintenance expense includes the impact of an increase in Generation's decommissioning obligation for spent nuclear fuel at Zion, certain acquisition costs and increased planned nuclear refueling outage costs associated with the higher number of refueling outage days in 2011. These unfavorable impacts were partially offset by higher revenues resulting from the expiration of the PECO PPA on December 31, 2010 and favorable portfolio and market conditions in the South and West region.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Generation's net income decreased compared to the same period in 2010 primarily due to mark-to-market losses on economic hedging activities, unfavorable NDT fund performance in 2011, higher nuclear fuel costs and higher operating and maintenance expenses. Higher depreciation and operating and maintenance expense includes the impact of an increase Generation's decommissioning obligation for spent nuclear fuel at Zion, certain acquisition costs and increased planned nuclear refueling outage costs associated with the higher number of refueling outage days in 2011. These unfavorable impacts were partially offset by higher revenues due to the expiration of the PECO PPA on December 31, 2010 and favorable portfolio and market conditions in the South and West region.

Revenue Net of Purchased Power and Fuel Expense

Generation has three reportable segments, the Mid-Atlantic, Midwest, and South and West regions representing the different geographical areas in which Generation's power marketing activities are conducted. Mid-Atlantic includes Generation's operations primarily in Pennsylvania, New Jersey and Maryland; Midwest includes the operations in Illinois, Indiana, Michigan and Minnesota; and the South and West includes operations primarily in Texas, Georgia, Oklahoma, Kansas, Missouri, Idaho and Oregon.

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 and PECO. 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 retail gas, proprietary trading, compensation under the reliability-must-run rate schedule, other revenues and mark-to-market activities are not allocated to a region.

For the three and nine months ended September 30, 2011 and 2010, Generation's revenue net of purchased power and fuel expense by region were as follows:

	Three Months Ended September 30,			
	2011	2010	Variance	% Change
Mid-Atlantic(a)(b)	$ 836	$ 564	$ 272	48.2%
Midwest(b)	853	1,044	(191)	(18.3%)
South and West	98	(11)	109	990.9%
Total electric revenue net of purchased power and fuel expense	$ 1,787	$ 1,597	$ 190	11.9%
Trading portfolio	2	—	2	n.m.
Mark-to-market gains (losses)	(91)	163	(254)	n.m.
Other(c)(d)	52	(50)	102	n.m.
Total revenue net of purchased power and fuel expense	$ 1,750	$ 1,710	$ 40	2.3%

	Nine Months Ended September 30, 2011	2010	Variance	% Change
Mid-Atlantic(a)(b)	$2,573	$1,760	$ 813	46.2%
Midwest(b)	2,704	3,054	(350)	(11.5%)
South and West	84	(102)	186	182.4%
Total electric revenue net of purchased power and fuel expense	$5,361	$4,712	$ 649	13.8%
Trading portfolio	24	25	(1)	(4.0%)
Mark-to-market gains (losses)	(363)	273	(636)	n.m.
Other(c)(d)	102	(24)	126	n.m.
Total revenue net of purchased power and fuel expense	$5,124	$4,986	$ 138	2.8%

(a) Included in the Mid-Atlantic region are the results of generation in New England.
(b) Results of transactions with PECO and ComEd are included in the Mid-Atlantic and Midwest regions, respectively.
(c) Includes retail gas activities and other miscellaneous revenues, which primarily include fuel sales and compensation under the reliability-must-run rate schedule.
(d) In 2010, Other also includes the $57 million impairment of certain emission allowances further described in Note 18 of the 2010 Form 10-K.

Generation's supply sources by region are summarized below:

Supply source (GWh)	Three Months Ended September 30, 2011	2010	Variance	% Change
Nuclear generation(a)				
Mid-Atlantic	12,158	12,076	82	0.7%
Midwest	23,887	23,675	212	0.9%
Fossil and renewable generation				
Mid-Atlantic(a)(b)	1,724	2,582	(858)	(33.2%)
Midwest(c)	88	16	72	n.m.
South and West(c)	1,463	691	772	111.7%
Purchased power(d)				
Mid-Atlantic	702	599	103	17.2%
Midwest	1,756	1,774	(18)	(1.0%)
South and West	3,815	4,084	(269)	(6.6%)
Total supply by region				
Mid-Atlantic	14,584	15,257	(673)	(4.4%)
Midwest	25,731	25,465	266	1.0%
South and West	5,278	4,775	503	10.5%
Total supply	45,593	45,497	96	0.2%

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Supply source (GWh)	Nine Months Ended September 30, 2011	2010	Variance	% Change
Nuclear generation(a)				
Mid-Atlantic	35,700	35,544	156	0.4%
Midwest	68,704	69,352	(648)	(0.9%)
Fossil and renewable generation				
Mid-Atlantic(a)(b)	5,943	7,321	(1,378)	(18.8%)
Midwest(c)	408	23	385	n.m.
South and West(c)	2,610	1,120	1,490	133.0%
Purchased power(d)				
Mid-Atlantic	2,159	1,476	683	46.3%
Midwest	4,827	5,256	(429)	(8.2%)
South and West	8,408	9,480	(1,072)	(11.3%)
Total supply by region				
Mid-Atlantic	43,802	44,341	(539)	(1.2%)
Midwest	73,939	74,631	(692)	(0.9%)
South and West	11,018	10,600	418	3.9%
Total supply	128,759	129,572	(813)	(0.6%)

(a) Includes Generation's proportionate share of the output of its jointly owned generating plants.

(b) Includes generation in New England and excludes revenue under the reliability-must-run rate schedule.

(c) Includes generation from Exelon Wind, acquired in December 2010, of 76 GWh and 385 GWh in the Midwest and 249 GWh and 1,038 GWh in the South and West for the three months and nine months ended September 30, 2011, respectively.

(d) Includes non-PPA purchases of 1,547 GWh and 1,594 GWh for the three months ended September 30, 2011 and 2010, respectively, and 2,771 GWh and 3,814 GWh for the nine months ended September 30, 2011 and 2010, respectively.

Generation's sales are summarized below:

Sales (GWh)(a)	Three Months Ended September 30, 2011	2010	Variance	% Change
PECO(c)	—	11,976	(11,976)	(100.0%)
Market and retail(d)	45,593	33,521	12,072	36.0%
Total electric sales	45,593	45,497	96	0.2%

Sales (GWh)(a)	Nine Months Ended September 30, 2011	2010	Variance	% Change
ComEd(b)	—	5,323	(5,323)	(100.0%)
PECO(c)	—	32,247	(32,247)	(100.0%)
Market and retail(d)	128,759	92,002	36,757	40.0%
Total electric sales	128,759	129,572	(813)	(0.6%)

(a) Excludes physical trading volumes of 1,679 GWh and 1,077 GWh for the three months ended September 30, 2011 and 2010, respectively, and 4,508 GWh and 2,885 GWh for the nine months ended September 30, 2011 and 2010, respectively.

(b) Represents sales under the 2006 ComEd auction.

(c) Represents sales under the full requirements PPA, which expired on December 31, 2010.

(d) Includes sales under the ComEd RFP, settlements under the ComEd swap and sales to PECO through the competitive procurement process.

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, 2011 as compared to the same periods in 2010.

	Three Months Ended September 30,		
$/MWh	2011	2010	% Change
Mid-Atlantic(a)(b)	$ 57.32	$ 36.97	55.0%
Midwest(a)(c)	$ 33.15	$ 41.00	(19.1%)
South and West	$ 18.57	$ (2.30)	907.4%
Electric revenue net of purchased power and fuel expense per MWh(d)	$ 39.19	$ 35.11	11.6%

	Nine Months Ended September 30,		
$/MWh	2011	2010	% Change
Mid-Atlantic(a)(b)	$ 58.74	$ 39.69	48.0%
Midwest(a)(c)	$ 36.57	$ 40.92	(10.6%)
South and West	$ 7.62	$ (9.62)	179.2%
Electric revenue net of purchased power and fuel expense per MWh(d)	$ 41.64	$ 36.37	14.5%

(a) Results of transactions with PECO and ComEd are included in the Mid-Atlantic and Midwest regions, respectively.
(b) Includes sales to PECO of $141 million (1,928 GWh) and $400 million (5,597 GWh) for the three and nine months ended September 30, 2011. Excludes compensation under the reliability-must-run rate schedule.
(c) Includes sales to ComEd of $67 million (1,653 GWh) and $118 million (2,907 GWh) and settlements of the ComEd swap of $92 million and $84 million for the three months ended September 30, 2011 and 2010, respectively. Includes sales to ComEd of $137 million (3,449 GWh) and $254 million (7,050 GWh) and settlements of the ComEd swap of $312 million and $234 million for the nine months ended September 30, 2011 and 2010, respectively.
(d) 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, 2011 and 2010 and excludes the mark-to-market impact of Generation's economic hedging activities, trading portfolio and other.

Mid-Atlantic

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. The increase in revenue net of purchased power and fuel expense in the Mid-Atlantic of $272 million was primarily due to increased realized margins on the volumes previously sold under Generation's PPA with PECO, which expired on December 31, 2010, partially offset by increased nuclear fuel costs.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. The increase in revenue net of purchased power and fuel expense in the Mid-Atlantic of $813 million was primarily due to increased realized margins on the volumes previously sold under Generation's PPA with PECO, which expired on December 31, 2010, partially offset by increased nuclear fuel costs.

Midwest

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. The decrease in revenue net of purchased power and fuel expense in the Midwest of $191 million was primarily due to lower capacity revenues, lower realized power prices and increased nuclear fuel costs, partially offset by increased revenues due to the acquisition of Exelon Wind in December 2010.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. The decrease in revenue net of purchased power and fuel expense in the Midwest of $350 million was primarily due to decreased realized margins in 2011 for the volumes previously sold under the 2006 ComEd auction contracts, higher congestion costs and increased nuclear fuel costs. These decreases were partially offset by increased capacity revenues, favorable settlements under the ComEd swap and the additional revenue from the acquisition of Exelon Wind in December 2010.

South and West

In the South and West, there are certain long-term purchase power agreements that have fixed capacity payments based on unit availability. The extent to which these fixed payments are recovered is dependent on market conditions.

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. The increase in revenue net of purchased power and fuel expense in the South and West of $109 million was primarily due to favorable pricing as a result of extreme weather and favorable market conditions in August 2011 and the additional revenue from the acquisition of Exelon Wind in December 2010.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. The increase in revenue net of purchased power and fuel expense in the South and West of $186 million was primarily driven by the performance of our generating units during extreme weather events that occurred in Texas in February and August 2011, in addition to the impact of additional revenue from the acquisition of Exelon Wind in December 2010 and higher realized margins due to favorable market conditions.

Mark-to-market

Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations.

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. Mark-to-market losses on power hedging activities were $71 million for the three months ended September 30, 2011, including the impact of the changes in ineffectiveness, compared to gains of $107 million for the three months ended September 30, 2010. Mark-to-market losses on fuel hedging activities were $20 million for the three months ended September 30, 2011 compared to gains of $56 million for the three months ended September 30, 2010. In general, the mark-to-market losses incurred in 2011 represent the realization of in-the-money hedge transactions during the period. See Notes 5 and 6 of the Combined Notes to the Consolidated Financial Statements for information on losses associated with mark-to-market derivatives.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Mark-to-market losses on power hedging activities were $260 million for the nine months ended September 30, 2011, including the impact of the changes in ineffectiveness, compared to gains of $142 million for the nine months ended September 30, 2010. Mark-to-market losses on fuel hedging activities were $103 million for the nine months ended September 30, 2011 compared to gains of $131 million for the nine months ended September 30, 2010. In general, the mark-to-market losses incurred in 2011 represent the realization of in-the-money hedge transactions during the period. See Notes 5 and 6 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, 2011 Compared to Three Months Ended September 30, 2010. The increase in other revenue net of purchased power and fuel expense is primarily due to the impacts of the impairment charge of certain emission allowances recognized in September 2010, additional other wholesale fuel sales in 2011, as well as the compensation under the reliability-must-run rate schedule further described in Note 11 of the Combined Notes to the Consolidated Financial Statements.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. The increase in other revenue net of purchased power and fuel expense is primarily due to the impacts of the impairment charge of certain emission allowances recognized in September 2010, as well as the compensation under the reliability-must-run rate schedule further described in Note 11 of the Combined Notes to the Consolidated Financial Statements.

Nuclear Fleet Capacity Factor and Production Costs

The following table presents nuclear fleet operating data for the three and nine months ended September 30, 2011 as compared to the same periods in September 30, 2010, 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,	
	2011	2010	2011	2010
Nuclear fleet capacity factor(a)	95.8%	95.4%	93.4%	94.2%
Nuclear fleet production cost per MWh(a)	$ 17.35	$ 15.61	$ 18.47	$ 17.00

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC.

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. The change in the nuclear fleet capacity factor was not material primarily because the increase in refueling outage days, excluding Salem outages, during the three months ended September 30, 2011 compared to the same period in 2010 was completely offset by the decrease in non-refueling outage days during comparable periods. For the three months ended September 30, 2011 and 2010, refueling outage days totaled 33 and 19, respectively. The increase in refueling outage days was primarily due to one additional refueling outage performed in 2011 compared to 2010. For the three months ended September 30, 2011 and 2010, non-refueling outage days totaled 3 and 19, respectively. 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, 2011 as compared to the same period in 2010.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. The nuclear fleet capacity factor decreased primarily due to more refueling outage days, excluding Salem outages, during the nine months ended September 30, 2011 compared to the same period in 2010 . For the nine months ended September 30, 2011 and 2010, refueling outage days totaled 180 and 164, respectively. Higher nuclear fuel costs, higher plant operating and maintenance expense and a lower number of net MWhs generated resulted in higher production cost per MWh for the nine months ended September 30, 2011 as compared to the same period in 2010.

Operating and Maintenance Expense

The changes in operating and maintenance expense for the three and nine months ended September 30, 2011 compared to the same periods in 2010, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Labor, other benefits, contracting and materials	$ 31	$ 81
Nuclear refueling outage costs, including the co-owned Salem plant(a)	25	35
Exelon Wind(b)	10	31
Asset retirement obligation increase(c)	28	28
Acquisition costs(d)	15	16
Other(e)	32	34
Increase in operating and maintenance expense	$ 141	$ 225

(a) Reflects the impact of increased planned refueling outages during the three and nine months ended September 30, 2011.
(b) Includes the costs of $7 million and $22 million for the three and nine months ended September 30, 2011, respectively, associated with labor, other benefits, contracting and materials.
(c) Reflects an increase in Generation's decommissioning obligation for spent nuclear fuel at Zion. See Note 9 for further information regarding the ARO update in 2011.
(d) Reflects certain costs associated with the acquisitions of Exelon Wind, Wolf Hollow, Antelope Valley and the proposed acquisition of Constellation.
(e) Includes additional environmental remediation costs recorded during the third quarter of 2011.

Depreciation and Amortization

The increase in depreciation and amortization for the three and nine months ended September 30, 2011 as compared to the three and nine months ended September 30, 2010 was primarily due to higher plant balances due to capital additions, upgrades to existing facilities and the acquisition of Exelon Wind. The increase in depreciation and amortization expense was also due to the change in the estimated useful life associated with the early retirement of Oyster Creek announced in December 2010. The change in estimated useful life is further described in Note 13 of the Combined Notes to Consolidated Financial Statements.

Taxes Other Than Income

The increase in taxes other than income for the three and nine months ended September 30, 2011 as compared to the three and nine months ended September 30, 2010 was primarily due to increased gross receipt taxes related to retail sales in the Mid-Atlantic region. These gross receipt taxes are recovered in revenue, and as a result, have no net impact to Generation's results of operations.

Interest Expense

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. The increase in interest expense for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010 was primarily due to an increase in long-term debt outstanding as a result of issuances in the third quarter of 2010.

Other, Net

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. The decrease in 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 a $36 million bargain purchase gain associated with the August 2011 acquisition of Wolf Hollow.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. The decrease in 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. The decrease in other, net is partially offset by 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 and a $36 million bargain purchase gain associated with the August 2011 acquisition of Wolf Hollow. Other, net also reflects $25 million of expense in 2011 compared to $48 million of expense in 2010 related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units.

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, 2011 and 2010:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net unrealized gains (losses) on decommissioning trust funds	$ (141)	$ 107	$ (88)	$ 48
Net realized gains (losses) on sale of decommissioning trust funds	$ (1)	$ 1	$ (3)	$ 1

Effective Income Tax Rate

Three Months Ended September 30, 2011 Compared to the Three Months Ended September 30, 2010. The effective income tax rate was 30.2% for the three months ended September 30, 2011 compared to 41.7% for the same period during 2010. The decrease in the effective income tax rate was primarily due to unrealized losses on the qualified decommissioning trust funds in 2011, compared to the unrealized gains in 2010. The effective income tax rate also decreased as the result of benefits associated with production tax credits at Exelon Wind. The decrease was partially offset by the impact of a reduction in Generation's manufacturing deduction benefits given reduced taxable income as a result of electing the safe harbor method of tax accounting for electric transmission and distribution property at ComEd and PECO for the 2011 and 2010 tax years.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. The effective income tax rate was 35.8% for the nine months ended September 30, 2011 compared to 35.9% for the same period during 2010.

See Note 8 of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in effective income tax rate.

Results of Operations — ComEd

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Favorable (Unfavorable) Variance
Operating revenues	$ 1,784	$ 1,918	$ (134)	$ 4,694	$ 4,832	$ (138)
Purchased power expense	932	1,112	180	2,436	2,636	200
Revenue net of purchased power expense(a)	852	806	46	2,258	2,196	62
Other operating expenses						
Operating and maintenance	353	298	(55)	846	733	(113)
Operating and maintenance for regulatory required programs	43	22	(21)	84	62	(22)
Depreciation and amortization	135	126	(9)	405	386	(19)
Taxes other than income	78	81	3	226	188	(38)
Total other operating expenses	609	527	(82)	1,561	1,369	(192)
Operating income	243	279	(36)	697	827	(130)
Other income and deductions						
Interest expense, net	(86)	(82)	(4)	(257)	(300)	43
Other, net	16	3	13	24	14	10
Total other income and deductions	(70)	(79)	9	(233)	(286)	53
Income before income taxes	173	200	(27)	464	541	(77)
Income taxes	61	79	18	169	295	126
Net income	$ 112	$ 121	$ (9)	$ 295	$ 246	$ 49

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

Net income

Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010. ComEd's net income for the three months ended September 30, 2011 was lower than the same period in 2010 primarily due to higher operating and maintenance expense resulting from several significant 2011 storms in ComEd's service territory. The decrease to net income was partially offset by higher electric distribution rates, effective June 1, 2011, pursuant to the ICC order in ComEd's 2010 rate case.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. ComEd's net income for the nine months ended September 30, 2011 was higher than the same period in 2010 primarily due to higher electric distribution rates effective, June 1, 2011 and one-time net benefits recognized in May 2011, pursuant to the ICC order in ComEd's 2010 rate case. In addition, net income was higher due to the remeasurement of uncertain income tax positions in 2010 related to the 1999 sale of ComEd's fossil generating assets. The remeasurement resulted in increased interest expense and income tax expense recorded in the second quarter of 2010. These increases to net income were partially offset by higher operating and maintenance expense resulting from several significant 2011 storms in ComEd's service territory, by the benefit recorded in 2010 resulting from the ICC's approval of ComEd's uncollectible accounts expense rider mechanism, and the accrual of estimated future Illinois utility distribution tax refunds for the 2008 and 2009 tax years recorded in the second quarter of 2010.

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 3 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process.

Electric revenues and purchased power expense are equally 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 249,714 and 61,822 at September 30, 2011 and 2010, respectively, representing 7% and 2% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 53% and 54% of ComEd's retail kWh sales for the three and nine months ended September 30, 2011, respectively, as compared to 49% and 51% for the three and nine months ended September 30, 2010, respectively.

The changes in ComEd's electric revenue net of purchased power expense for the three and nine months ended September 30, 2011 compared to the same periods in 2010 consisted of the following:

	Three Months Ended September 30, 2011 Increase (Decrease)	Nine Months Ended September 30, 2011 Increase (Decrease)
Pricing (2010 Rate Case)	$ 44	$ 57
Revenues subject to refund, net	23	3
Regulatory required programs cost recovery	21	22
Transmission	4	9
Volume — delivery	(7)	(12)
Weather — delivery	(9)	(10)
Uncollectible accounts recovery, net	(10)	(15)
Other	(20)	8
Total increase	$ 46	$ 62

Pricing (2010 Rate Case)

The ICC issued an order in the 2010 Rate Case approving an increase in ComEd's annual electric distribution revenue requirement. The order became effective June 1, 2011 resulting in higher revenues for the three and nine months ended September 30, 2011 compared to the same periods in 2010. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Revenues subject to refund, net

ComEd records revenues subject to refund based upon its best estimate of customer collections that may be required to be refunded. As a result of the September 30, 2010 Illinois Appellate Court (Court) decision in the 2007 Rate Case that ruled against ComEd on the treatment of post-test year accumulated depreciation and the recovery of system modernization costs via Rider SMP, ComEd began recording revenue subject to refund prospectively. 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, ComEd has updated its revenue subject to refund reserve. As of September 30, 2011, ComEd has recorded its best estimate of any refund obligations. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory required programs cost recovery

Revenues related to regulatory required programs are the recoveries from customers of costs for various legislative and/or regulatory programs on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating and maintenance for regulatory required programs during the periods presented. See Note 3 of the Combined Notes to Financial Statements for additional information.

Transmission

ComEd's transmission rates are established based on a FERC-approved formula. ComEd's most recent annual formula rate update, filed in May 2011, reflects actual 2010 expenses and investments plus forecasted 2011 capital additions. Transmission revenues net of purchased power expense vary from year to year based upon fluctuations in the underlying costs and investments being recovered. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

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 and small commercial and industrial customer for the three and nine months ended September 30, 2011, compared to the same periods in 2010.

Weather — delivery

Revenues net of purchased power expense were lower in the three and nine months ended September 30, 2011, compared to the same periods in 2010, due to unfavorable weather conditions, despite setting a new record for highest daily peak load experienced to date of 23,753 MWs on July 20, 2011. 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.

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, 2011 and 2010, consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2011**	**2010**	**Normal**	**From 2010**	**From Normal**
Three Months Ended September 30,					
Heating Degree-Days	147	70	110	110.0 %	33.6%
Cooling Degree-Days	785	854	624	(8.1)%	25.8%
Nine Months Ended September 30,					
Heating Degree-Days	4,302	3,699	4,084	16.3 %	5.3%
Cooling Degree-Days	1,022	1,166	848	(12.3)%	20.5%

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Uncollectible accounts recovery, net

Represents recoveries under ComEd's uncollectible accounts tariff.

Other

Other revenues, which can vary period to period, include rental revenues, revenues related to late payment charges, assistance provided to unaffiliated utilities through mutual assistance programs and recoveries of environmental remediation costs associated with MGP sites.

Operating and Maintenance Expense

The changes in operating and maintenance expense for the three and nine months ended September 30, 2011 compared to the same periods in 2010, consisted of the following:

	Three Months Ended September 30 Increase (Decrease)	Nine Months Ended September 30 Increase (Decrease)
Uncollectible accounts expense(a)		
One-time impact of 2010 ICC order(b)	$ —	$ 60
Provision	3	5
Recovery, net(c)	(13)	(20)
	(10)	45
Storm-related costs(d)	67	72
Labor, other benefits, contracting and materials	9	43
Discrete impacts from 2010 Rate Case order(e)	—	(32)
Other	(11)	(15)
Increase in operating and maintenance expense	$ 55	$ 113

(a) 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.

(b) As a result of the February 2010 ICC order, ComEd recorded a regulatory asset of $70 million and an offsetting reduction in operating and maintenance expense for the cumulative prior period under-collections in the first quarter of 2010. In addition, ComEd recorded a one-time contribution of $10 million associated with this legislation in the first quarter of 2010.

(c) Represents impacts on recoveries under ComEd's uncollectible accounts tariff.

(d) During the third quarter of 2011, several large storms impacted ComEd's service territory. Specifically, on July 11, 2011, severe, damaging straight line winds struck the ComEd service territory affecting 907,000 customers; the worst storm in terms of damage and customer impact in ComEd's history. ComEd's restoration efforts included significant costs associated with employee overtime, support from other utilities and incremental equipment and supplies.

(e) 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.

Operating and Maintenance Expense for Regulatory Required Programs

Operating and maintenance expense 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 during the period. See Note 3 of the Combined Notes to the Consolidated Financial Statements for additional information.

Depreciation and Amortization Expense

Depreciation and amortization expense increased during the three and nine months ended September 30, 2011 compared to the same periods in 2010, primarily due to higher plant balances.

Taxes Other Than Income

Three Months Ended September 30, 2011 Compared to the Three Months Ended September 30, 2010. Taxes other than income taxes decreased during the three months ended September 30, 2011 compared to the same period in 2010 as a result of decreased franchise and Illinois utility distribution taxes due to lower volumes delivered in 2011.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Taxes other than income taxes increased during the nine ended September 30, 2011 compared to the same period in 2010 primarily reflecting the accrual of estimated future refunds of Illinois utility distribution tax recorded in the second quarter of 2010 for the 2008 and 2009 tax years. Previously, ComEd had recorded refunds of the Illinois utility distribution tax when received. Due to sufficient, reliable evidence, ComEd began in June 2010 recording an estimated receivable associated with anticipated Illinois utility distribution tax refunds prospectively.

Interest Expense, net

Three Months Ended September 30, 2011 Compared to the Three Months Ended September 30, 2010. Interest expense increased during the three months ended September 30, 2011 compared to the same period in 2010 primarily due to higher outstanding debt balances.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. Interest expense decreased during the nine months ended September 30, 2011 compared to the same period in 2010 primarily due to $59 million of interest expense associated with the remeasurement of uncertain income tax positions related to the 1999 sale of ComEd’s fossil generating assets recorded in the second quarter of 2010. This decrease was partially offset by higher interest expense associated with higher outstanding debt balances. See Note 8 of the Combined Notes to Consolidated Financial Statements for additional information.

Other, net

Other, net increased during the three and nine months ended September 30, 2011 compared to the same periods in 2010 primarily due to an increase in interest income related to uncertain income tax positions. See Note 14 of the Combined Notes to Consolidated Financial Statements for further details on the components of Other, Net.

Effective Income Tax Rate

Three Months Ended September 30, 2011 Compared to the Three Months Ended September 30, 2010. The effective income tax rate was 35.3% for the three months ended September 30, 2011 compared to 39.5% for the same period during 2010. The decrease in the effective income tax rate was primarily due to lower state income taxes resulting from a tax method change for transmission and distribution property repairs. See Note 8 of the Combined Notes to Consolidated Financial Statements for further discussion of the change in the effective income tax rate.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010. The effective income tax rate was 36.4% for the nine months ended September 30, 2011 compared to 54.5% for the same period during 2010. The decrease in the effective income tax rate was primarily due to the remeasurement of uncertain income tax positions recorded in the second quarter of 2010 related to the 1999 sale of ComEd’s fossil generating assets. The effective income tax rate also decreased as the result of a one-time net benefit recorded in the second quarter of 2011, pursuant to the 2010 Rate Case order, to recover previously incurred income tax expense related to the passage of Federal health care legislation in the first quarter of 2010.

See Note 8 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, 2011	2010	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)				
Residential	8,877	9,361	(5.2)%	(2.4)%
Small commercial & industrial	8,811	9,110	(3.3)%	(2.2)%
Large commercial & industrial	7,494	7,503	(0.1)%	0.1%
Public authorities & electric railroads	303	283	7.1%	10.5%
Total Retail	25,485	26,257	(2.9)%	(1.4)%

Retail Deliveries to customers (in GWhs)	Nine Months Ended September 30, 2011	2010	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)				
Residential	22,108	22,778	(2.9)%	(2.0)%
Small commercial & industrial	24,648	24,975	(1.3)%	(0.7)%
Large commercial & industrial	21,011	20,991	0.1%	0.2%
Public authorities & electric railroads	919	927	(0.9)%	(0.5)%
Total Retail	68,686	69,671	(1.4)%	(0.8)%

Number of Electric Customers	As of September 30, 2011	2010
Residential	3,439,704	3,422,824
Small commercial & industrial	364,917	361,424
Large commercial & industrial	2,041	2,014
Public authorities & electric railroads	4,801	5,090
Total	3,811,463	3,791,352

Electric Revenue	Three Months Ended September 30, 2011	2010	% Change	Nine Months Ended September 30, 2011	2010	% Change
Retail Delivery and Sales(a)						
Residential	$ 1,112	$ 1,181	(5.8)%	$ 2,746	$ 2,788	(1.5)%
Small commercial & industrial	410	471	(13.0)%	1,177	1,273	(7.5)%
Large commercial & industrial	102	109	(6.4)%	288	306	(5.9)%
Public authorities & electric railroads	12	14	(14.3)%	38	48	(20.8)%
Total Retail	1,636	1,775	(7.8)%	4,249	4,415	(3.8)%
Other Revenue(b)	148	143	3.5%	445	417	6.7%
Total Electric Revenues	$ 1,784	$ 1,918	(7.0)%	$ 4,694	$ 4,832	(2.9)%

(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.

(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,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2011	2010		2011	2010	
Operating revenues	$ 946	$ 1,495	$ (549)	$2,942	$4,220	$ (1,278)
Purchased power and fuel	464	673	209	1,506	1,987	481
Revenue net of purchased power and fuel(a)	482	822	(340)	1,436	2,233	(797)
Other operating expenses						
Operating and maintenance	203	176	(27)	543	507	(36)
Operating and maintenance for regulatory required programs	16	15	(1)	54	36	(18)
Depreciation and amortization	51	326	275	150	859	709
Taxes other than income	59	90	31	165	240	75
Total other operating expenses	329	607	278	912	1,642	730
Operating income	153	215	(62)	524	591	(67)
Other income and deductions						
Interest expense, net	(34)	(38)	4	(102)	(160)	58
Other, net	3	3	—	11	6	5
Total other income and deductions	(31)	(35)	4	(91)	(154)	63
Income before income taxes	122	180	(58)	433	437	(4)
Income taxes	17	53	36	119	134	15
Net income	105	127	(22)	314	303	11
Preferred security dividends	1	1	—	3	3	—
Net income on common stock	$ 104	$ 126	$ (22)	$ 311	$ 300	$ 11

(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

The decrease in net income for the three months ended September 30, 2011 compared to the same period in 2010 primarily related to increased storm costs and the net impact of 2010 CTC recoveries reflected in electric operating revenues net of purchased power expense and CTC amortization expense, both of which ceased at the end of the transition period on December 31, 2010. These decreases in net income were partially offset by the new distribution rates effective January 1, 2011 as a result of the 2010 electric and natural gas rate case settlements, decreased bad debt and interest expense, as well as decreased income tax expense reflecting the impact of electing the safe harbor method of tax accounting for electric transmission and distribution property. See Note 8 of the Combined Notes to the Consolidated Financial Statements for further discussion of the election of the safe harbor method.

The increase in net income for the nine months ended September 30, 2011 compared to the same period in 2010 primarily related to the new distribution rates, decreased interest expense related to the retirement of the PETT transition bonds on September 1, 2010 and the impact of the change in measurement of uncertain tax positions in the second quarter of 2010, and decreased income tax expense related to the election of the safe harbor method. These increases in net income were partially offset by increased storm costs and the net impact of 2010 CTC recoveries reflected in electric operating revenues net of purchased power expense and CTC amortization expense, both of which ceased at the end of the transition period on December 31, 2010.

Operating Revenues, Purchased Power and Fuel Expense

There are certain drivers to operating revenues that are offset by their impact on purchased power and fuel expense, such as commodity procurement costs and customer choice programs. PECO's electric generation rates charged to customers were capped until December 31, 2010 in accordance with the 1998 restructuring settlement. Beginning January 1, 2011, PECO's electric generation rates are based on actual costs incurred through its approved competitive market procurement process. Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric generation 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 revenues and purchased power expense are also affected by fluctuations in participation in the customer choice program. All PECO customers have the choice to purchase energy from a competitive electric generation supplier. The customer choice of electric generation suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service. Customer choice program activity has no impact on net income. The number of retail customers purchasing energy from a competitive electric generation supplier was 351,532 and 21,475 at September 30, 2011 and 2010, respectively, representing 22% and 1% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 60% and 54% of PECO's retail kWh sales for the three and nine months ended September 30, 2011, respectively compared to 1% for the three and nine months ended September 30, 2010.

The changes in PECO's operating revenues net of purchased power and fuel expense for the three months ended September 30, 2011 compared to the same period in 2010 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ (9)	$ (1)	$ (10)
Volume	1	1	2
CTC recoveries	(351)	—	(351)
Regulatory program cost recovery	1	—	1
Pricing	29	2	31
Other	(14)	1	(13)
Total increase (decrease)	$ (343)	$ 3	$(340)

The changes in PECO's operating revenues net of purchased power and fuel expense for the nine months ended September 30, 2011 compared to the same period in 2010 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ (16)	$ 5	$ (11)
Volume	(4)	1	(3)
CTC recoveries	(906)	—	(906)
Regulatory program cost recovery	20	—	20
Pricing	104	12	116
Customer mix	11	1	12
Other	(26)	1	(25)
Total increase (decrease)	$ (817)	$20	$(797)

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, 2011 compared to the same period in 2010, electric operating revenues net of purchased power expense were lower due to unfavorable weather conditions during the third quarter of 2011 in PECO's service territory compared to the same period in 2010.

During the nine months ended September 30, 2011 compared to the same period in 2010, electric operating revenues net of purchased power expense were lower due to unfavorable weather conditions during the second and third quarters of 2011 in PECO's service territory compared to the same periods in 2010 despite setting a new record for highest peak load experienced to date of 8,983 MWs on July 22, 2011. Gas revenues net of fuel expense were higher due to favorable weather conditions in the first quarter of 2011 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, 2011 compared to the same periods in 2010 and normal weather consisted of the following:

				% Change	
Heating and Cooling Degree-Days	2011	2010	Normal	From 2010	From Normal
Three Months Ended September 30,					
Heating Degree-Days	18	—	36	n/a	(50.0)%
Cooling Degree-Days	1,109	1,212	939	(8.5)%	18.1%
Nine Months Ended September 30,					
Heating Degree-Days	2,855	2,710	3,004	5.4%	(5.0)%
Cooling Degree-Days	1,603	1,798	1,271	(10.8)%	26.1%

Volume

The decrease in electric operating revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, for the nine months ended September 30, 2011 compared to the same period in 2010 reflected the impact of energy efficiency initiatives on customer usage. See Note 3 of the Combined Notes to Consolidated Financial Statements for further information.

CTC Recoveries

The decrease in electric revenues net of purchased power expense related to CTC recoveries for the three and nine months ended September 30, 2011 compared to the same periods in 2010 reflected the absence of the CTC charge component that was included in rates charged to customers in 2010. PECO fully recovered all stranded costs during the final year of the transition period that expired on December 31, 2010.

Regulatory Program Cost Recovery

The increase in electric revenues net of purchased power expense relating to regulatory program cost recovery for the three and nine months ended September 30, 2011 compared to the same periods in 2010 primarily related to increased recovery of costs on the energy efficiency and smart meter programs as well as administrative costs for the GSA and AEPS programs that began January 1, 2011. There are equal and offsetting expenses included in operating and maintenance for regulatory required programs, depreciation and amortization expense, and income taxes.

Pricing

The increase in operating revenues net of purchased power and fuel expense as a result of pricing for the three and nine months ended September 30, 2011 compared to the same periods in 2010 primarily reflected the impact of the new electric and natural gas distribution rates charged to customers that became effective January 1, 2011 in accordance with the 2010 PAPUC approved electric and natural gas distribution rate case settlements. See Note 3 of the Combined Notes to the Consolidated Financial Statements for further information.

Customer Mix

The increase in operating revenues net of purchased power and fuel expense as a result of customer mix for the nine months ended September 30, 2011 compared to the same period in 2010, reflected an increase in revenues associated with volume shifts among customer classes, which resulted in a different profile of rates as different customer classes are charged different rates.

Other

The decrease in electric operating revenues net of purchased power expense for the three and nine months ended September 30, 2011 compared to the same periods in 2010 primarily reflected a decrease in GRT revenue as a result of lower retail transmission and supplied energy service revenue earned by PECO due to increased participation in the customer choice program. There is an equal and offsetting decrease in GRT expense included in taxes other than income. This decrease was partially offset by an increase in wholesale transmission revenue earned by PECO as a transmission owner for the use of PECO's transmission facilities in PJM. The rates charged for wholesale transmission are based on the prior year's peak, and the peak in 2010 was higher than in 2009.

Operating and Maintenance Expense

The increase in operating and maintenance expense for the three and nine months ended September 30, 2011 compared to the same period in 2010, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Labor, other benefits, contracting and materials	$ 6	$ 28
Storm-related costs	25	10
Uncollectible accounts expense	(7)	(1)
2010 Non-Cash Charge Resulting from Health Care Legislation	—	(2)
Other	3	1
Increase in operating and maintenance expense	$ 27	$ 36

Storm-related costs

On August 27, 2011, Hurricane Irene hit PECO's service territory interrupting electric service to approximately 500,000 customers. PECO restored power to 99% of customers within 72 hours of the storm. Hurricane Irene ranks as one of the top five worst storms in PECO history.

Operating and Maintenance for Regulatory Required Programs

Operating and maintenance expenses related to regulatory required programs consists of costs 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 during the current periods. The increase in operating and maintenance for regulatory required programs during the three months ended September 30, 2011 compared to the same period in 2010 primarily reflected $3 million related to smart meter programs and $1 million related to GSA administrative costs partially offset by a $3 million decrease related to energy efficiency programs. The increase in operating and maintenance for regulatory required programs during the nine months ended September 30, 2011 compared to the same period in 2010 reflected $7 million related to smart meter programs, $3 million related to GSA administrative costs and an increase of $8 million related to energy efficiency programs. See Note 3 of the Combined Notes to the Consolidated Financial Statements for further information.

Depreciation and Amortization Expense

The decrease in depreciation and amortization expense for the three and nine months ended September 30, 2011 compared to the same periods in 2010 was primarily due to a decrease in the CTC amortization of $281 million and $725 million, respectively, which was fully amortized as of December 31, 2010.

Taxes Other Than Income

The decrease in taxes other than income for the three and nine months ended September 30, 2011 compared to the same periods in 2010 was primarily due to decreased GRT collections as a result of lower revenues. An equal and offsetting decrease in GRT revenue has been reflected in operating revenues during the current periods.

Interest Expense, Net

The decrease in interest expense, net for the nine months ended September 30, 2011 compared to the same period in 2010 was primarily due to decreased interest expense as a result of the retirement of PETT transition bonds on September 1, 2010 and the impact of interest expense incurred in June 2010 related to the change in measurement of uncertain tax positions in accordance with accounting guidance.

Other, Net

The increase in other, net for the nine months ended September 30, 2011 compared to the same period in 2010 primarily related to increased investment income and AFUDC — Equity.

Effective Income Tax Rate

PECO's effective income tax rate was 13.9% and 29.4% for the three months ended September 30, 2011 and 2010, respectively, and 27.5% and 30.7% for the nine months ended September 30, 2011 and 2010, respectively. The decrease in the effective income tax rate for the three and nine months ended September 30, 2011 compared to the same periods in 2010 primarily related to the impact of electing the safe harbor method of tax accounting for electric transmission and distribution property. See Note 8 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, 2011	Three Months Ended September 30, 2010	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)								
Residential	4,085	4,144	(1.4)%	2.1%	10,750	10,789	(0.4)%	1.9%
Small commercial & industrial	2,272	2,368	(4.1)%	(3.2)%	6,437	6,545	(1.7)%	(1.0)%
Large commercial & industrial	4,370	4,447	(1.7)%	(0.6)%	12,012	12,397	(3.1)%	(2.2)%
Public authorities & electric railroads	239	228	4.8%	6.4%	710	699	1.6%	3.3%
Total Electric Retail	10,966	11,187	(2.0)%	(0.1)%	29,909	30,430	(1.7)%	(0.4)%

Number of Electric Customers	As of September 30, 2011	As of September 30, 2010
Residential	1,412,070	1,408,239
Small commercial & industrial	156,769	156,502
Large commercial & industrial	3,116	3,092
Public authorities & electric railroads	1,123	984
Total	1,573,078	1,568,817

Electric Revenue	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	% Change	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	% Change
Retail Delivery and Sales (a)						
Residential	$ 598	$ 663	(9.8)%	$ 1,542	$ 1,625	(5.1)%
Small commercial & industrial	138	308	(55.2)%	471	827	(43.0)%
Large commercial & industrial	84	374	(77.5)%	259	1,035	(75.0)%
Public authorities & electric railroads	9	20	(55.0)%	29	67	(56.7)%
Total Retail	829	1,365	(39.3)%	2,301	3,554	(35.3)%
Other Revenue	62	74	(16.2)%	186	194	(4.1)%
Total Electric Revenues	$ 891	$ 1,439	(38.1)%	$ 2,487	$ 3,748	(33.6)%

(a) Reflects delivery revenues and volumes 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.

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PECO Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	% Change	Weather-Normal % Change
Retail Delivery and Sales(b)								
Retail sales	3,687	3,546	4.0%	7.2%	38,982	37,103	5.1%	0.9%
Transportation and other	6,190	8,501	(27.2)%	(29.1)%	21,428	23,658	(9.4)%	(8.4)%
Total Gas Deliveries	9,877	12,047	(18.0)%	(18.5)%	60,410	60,761	(0.6)%	(2.5)%

Number of Gas Customers	As of September 30, 2011	As of September 30, 2010
Residential	448,763	446,348
Commercial & industrial	40,883	40,863
Total Retail	489,646	487,211
Transportation	868	834
Total	490,514	488,045

Gas revenue	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	% Change	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	% Change
Retail Delivery and Sales(b)						
Retail sales	$ 50	$ 52	(3.8)%	$ 428	$ 451	(5.1)%
Transportation and other	5	4	25.0%	27	21	28.6%
Total Gas Deliveries	$ 55	$ 56	(1.8)%	$ 455	$ 472	(3.6)%

(b) Reflects delivery revenues and volumes 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. The cost of natural gas is charged to customers purchasing natural gas from PECO.

Liquidity and Capital Resources

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 and PECO have access to unsecured revolving credit facilities with aggregate bank commitments of $500 million, $5.3 billion, $1 billion and $600 million, respectively. Additionally, Generation has access to a supplemental credit facility with an aggregate available commitment of $300 million. The Registrants' credit facilities extend through March 2016 for Exelon, Generation and PECO and March 2013 for ComEd. Availability under the supplemental facility extends through December 2015 for $150 million of the $300 million commitment and March 2016 for the remaining $150 million. Exelon, Generation, ComEd and PECO 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 and PECO 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 7 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 and PECO's cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO, gas distribution services. ComEd's and PECO's distribution services are provided to an established and diverse base of retail customers. ComEd's and PECO'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 3 and 13 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. 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 postretirement welfare plans at September 30, 2011 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 Exelon's pension and other postretirement benefit plans were 4.82% and 4.89%, respectively, at September 30, 2011, and 5.26% and 5.30%, respectively, at December 31, 2010. Exelon's pension and other postretirement benefit plans experienced actual asset returns of approximately 5% and (3)%, respectively, for the nine months ended September 30, 2011. Exelon's $2.1 billion pension contribution in January 2011, in conjunction with its investment strategy to reduce the risk profile of its portfolio of pension assets, has partly mitigated the impact of lower discount rates on Exelon's pension obligation. See Note 10 — Retirement Benefits for additional information on Exelon's pension investment strategy.

Based on these assumptions, Exelon has estimated the unfunded status of the pension and other postretirement benefit plans at September 30, 2011 to be $2,317 million and $2,679 million, respectively, representing a funded status percentage of 83% and 36%, respectively. The pension unfunded status has improved by $1,348 million since December 31, 2010 primarily due to the $2.1 billion pension contribution made in January 2011, partially offset by the decrease in discount rates from December 31, 2010. The other postretirement benefit plan unfunded status has increased by $460 million since December 31, 2010 primarily due to the decrease in discount rates from December 31, 2010.

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 contributed $2.1 billion to its pension plans in January 2011, representing substantially all currently planned 2011 qualified pension plan contributions, of which Generation, ComEd and PECO contributed $952 million, $871 million and $110 million, respectively. Exelon funded the $2.1 billion contribution with $500 million from cash from operations, $750 million from the tax benefits of making the pension contributions and $850 million associated with the accelerated cash tax benefits from the 100% bonus depreciation provision enacted as part of the Tax Relief Act of 2010.

Management has estimated its future pension contributions at September 30, 2011, incorporating current projected discount rates and actual census data as of January 1, 2011. The estimated pension contributions summarized below include ERISA minimum-required contributions, contributions necessary to avoid benefit restrictions and at-risk status, and payments related to the non-qualified pension plans; these estimates do not include any incremental contributions Exelon may elect to make in these future periods:

	2012	2013	2014	2015	2016	Cumulative
Estimated pension contributions	$140	$130	$140	$725	$675	$ 1,810

To the extent interest rates continue to decline or the pension plans do not earn the expected asset return rates (assumed at 8% as of December 31, 2010), annual pension contribution requirements in future years could increase and such increases could be significant, especially in years 2013 and beyond.

Unlike the qualified pension plans, Exelon's other postretirement plans are not subject to regulatory minimum contribution requirements. Management considers several factors in determining the level of contributions to Exelon's 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). Exelon expects to contribute $271 million to its other postretirement benefit plans in the fourth quarter of 2011, of which Generation, ComEd and PECO expect to contribute $118 million, $105 million and $28 million, respectively. The Registrants expect to contribute an aggregate of approximately $265-315 million annually from 2012 to 2016 to 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 2011, and that Exelon will receive additional tax refunds of approximately $365 million between 2012 and 2014. In order to stop additional interest from accruing on the IRS expected assessment, Exelon made a payment in December 2010 to the IRS of $302 million. During 2010, Exelon and IRS Appeals failed to reach a settlement with respect to the like-kind exchange position and the related substantial understatement penalty. See Note 8 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.
- On August 19, 2011, the IRS issued Revenue Procedure 2011-43 that provides a safe harbor method of tax accounting for electric transmission and distribution property. ComEd intends to adopt the safe harbor in the Revenue Procedure in future periods as the associated tax cash benefits are received for the 2011 tax year. PECO adopted the safe harbor for the 2010 tax year. This change to the newly prescribed method will result in an initial cash tax benefit (primarily in 2011) at Exelon, ComEd and PECO in the amount of approximately $300 million, $250 million and $95 million, respectively, partially offset by a cash tax detriment at Generation in the amount of $28 million. See Note 3 of the Combined Notes to Consolidated Financial Statements for discussion of the regulatory treatment prescribed in the 2010 electric distribution rate case settlement for PECO's cash tax benefit resulting from the application of the method change to years prior to 2010.
- 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, is eligible for 100% bonus depreciation. Additionally, qualifying property placed into service during 2012 is eligible for 50% bonus depreciation. These provisions will generate approximately $1 billion of cash for Exelon (approximately $850 million in 2011 and approximately $170 million 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 and PECO generally increase future revenue requirements, the bonus depreciation associated with these capital additions will partially mitigate any future rate increases through the ratemaking process. See Note 10 of the Combined Notes to the Financial Statements for further details regarding the use of the cash generated under the Tax Relief Act of 2010.

- 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. See Note 8 of the Combined Notes to the Financial Statements for further details regarding the 2011 Illinois State Tax Rate Legislation, which increases the corporate income tax rate in Illinois.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the nine months ended September 30, 2011 and 2010:

	Nine Months Ended September 30, 2011	2010	Variance
Net income	$ 1,889	$2,039	$ (150)
Add (subtract):			
Non-cash operating activities(a)	3,863	2,633	1,230
Pension and non-pension postretirement benefit contributions	(2,089)	(740)	(1,349)
Income taxes	532	310	222
Changes in working capital and other noncurrent assets and liabilities(b)	(530)	(318)	(212)
Option premiums received (paid), net	59	(101)	160
Counterparty collateral received (posted), net	(807)	289	(1,096)
Net cash flows provided by operations	$ 2,917	$4,112	$(1,195)

(a) Represents depreciation, amortization and accretion, mark-to-market gains and losses on derivative transactions, deferred income taxes, provision for uncollectible accounts, pension and non-pension postretirement benefit expense, equity in earnings and loss in equity method 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, 2011 and 2010 by Registrant were as follows:

	Nine Months Ended September 30, 2011	2010
Exelon	$2,917	$4,112
Generation	2,122	2,563
ComEd	615	642
PECO	656	919

Changes in Exelon's, Generation's, ComEd's and PECO'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, 2011 and 2010 were as follows:

Generation

- During the nine months ended September 30, 2011 and 2010, Generation had net (payments) receipts of counterparty collateral of $(804) million and $443 million, respectively. Net payments during the nine months ended September 30, 2011 and 2010 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, 2011 and 2010, Generation had net collections (payments) of approximately $59 million and $(101) million, respectively, related to the purchase and sales of options. The level of option activity in a given period may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During the nine months ended September 30, 2011 and 2010, ComEd's net payables to Generation for energy purchases related to its supplier forward contract, ICC-approved RFP contracts and financial swap contract decreased by $1 million and $90 million, respectively. During the nine months ended September 30, 2011 and 2010, ComEd's payables to other energy suppliers for energy purchases decreased by $67 million and $8 million, respectively.
- During the nine months ended September 30, 2011, ComEd posted $6 million of incremental cash collateral to PJM due to seasonal variations in its energy transmission activity levels. As of September 30, 2011, ComEd had $159 million of collateral remaining at PJM.

PECO

- During the nine months ended September 30, 2011 and 2010, PECO's payables to Generation for energy purchases decreased by $211 million and $16 million, respectively. During the nine months ended September 30, 2011 and 2010, PECO's payables to other energy suppliers for energy purchases increased by $95 million and $2 million, respectively.
- During the nine months ended September 30, 2011 and 2010, PECO's prepaid utility taxes increased by $40 million and $31 million, respectively, primarily due to the Pennsylvania GRT prepayment in March of each year.

Cash Flows from Investing Activities

Cash flows provided by (used in) investing activities for the nine months ended September 30, 2011 and 2010 by Registrant were as follows:

	Nine Months Ended September 30,	
	2011	2010
Exelon	$(4,031)	$(2,037)
Generation	(2,421)	(1,501)
ComEd	(1,276)	(670)
PECO	(402)	61

Capital expenditures by Registrant for the nine months ended September 30, 2011 and 2010 and projected amounts for the full year 2011 are as follows:

	Projected Full Year(a)	Nine Months Ended September 30,	
	2011	2011	2010
Generation(b)	$ 2,726	$1,865	$1,405
ComEd	1,032	758	686
PECO	477	321	358
Other(c)	41	28	(67)
Exelon	$ 4,276	$2,972	$2,382

(a) The projected capital expenditures do not include adjustments for non-cash activity.
(b) Includes nuclear fuel.
(c) Other primarily consists of corporate operations and BSC. The negative capital expenditures for Other for the nine months ended September 30, 2010 primarily related to the transfer of information technology hardware and software assets from BSC to PECO.

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

Generation

Approximately 39% of the projected 2011 capital expenditures at Generation are for the acquisition of nuclear fuel, with the remaining amounts primarily reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Included in the projected 2011 capital expenditures are a portion of the costs of a series of planned power uprates across Generation's nuclear fleet and a portion of the Antelope Valley construction costs. See "EXELON CORPORATION — Executive Overview," for more information on nuclear uprates.

ComEd and PECO

Approximately 83% and 73% of the projected 2011 capital expenditures at ComEd and PECO, respectively, are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as PECO's transmission system reliability upgrades required by PJM related to Generation's plant retirements. The remaining amounts are for capital additions to support new business and customer growth, which for PECO includes capital expenditures related to its smart meter program and SGIG project, net of DOE expected reimbursements. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

On November 30, 2010, NERC provided guidance to transmission owners that will require ComEd and PECO to 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. ComEd and PECO may be required to incur incremental capital expenditures, which may be significant at ComEd, associated with this guidance upon completion of the assessments. Specific projects and expenditures will not be identified until the assessments are completed. ComEd and PECO are each continuing to evaluate their total capital spending requirements. ComEd and PECO anticipate that they will fund their capital expenditures with internally generated funds and borrowings.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the nine months ended September 30, 2011 and 2010 by Registrant were as follows:

	Nine Months Ended September 30,	
	2011	2010
Exelon	$ 573	$ (1,350)
Generation	(14)	48
ComEd	967	(29)
PECO	(258)	(851)

Debt

See Note 7 of the Combined Notes to the 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, 2011 and 2010 by Registrant were as follows:

	Nine Months Ended September 30,	
	2011	2010
Exelon	$1,044	$1,042
Generation	61	623
ComEd	225	225
PECO	271	181

Short-Term Borrowings

During the nine months ended September 30, 2011, Exelon and Exelon Generation issued $389 million and $73 million of commercial paper, respectively. During the nine months ended September 30, 2010, ComEd repaid $155 million of outstanding borrowings under its credit agreement and issued $65 million of commercial paper.

Contributions from Parent/Member

Contributions from Parent/Member (Exelon) during the nine months ended September 30, 2011 and 2010 by Registrant were as follows:

	Nine Months Ended September 30,	
	2011	2010
Generation	$ 30	$ 3
ComEd	—	2
PECO(a)	18	136

(a) $135 million for the nine months ended September 30, 2010 reflects payments received to reduce the parent receivable. The balance of the parent receivable was paid in full as of December 2010.

Other

For the nine months ended September 30, 2011, other financing activities primarily consist of expenses paid related to the replacement of the Registrants' credit facilities. See Note 7 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 $7.7 billion in aggregate total commitments of which $6.9 billion was available as of September 30, 2011, and of which no financial institution has more than 9% of the aggregate commitments. Exelon, Generation, ComEd and PECO had access to the commercial paper market during the third quarter of 2011. 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 2010 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 operations, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of September 30, 2011, it would have been required to provide incremental collateral of $1,155 million, which is well within its current available credit facility capacities of $5.4 billion. The $1,155 million includes $948 million of collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements and $207 million of financial assurances that Generation would be required to provide Nuclear Electric Insurance Limited related to annual retrospective premium obligations. If ComEd lost its investment grade credit rating as of September 30, 2011, it would have been required to provide incremental collateral of $214 million, which is well within its current available credit facility capacity of $804 million, which takes into account commercial paper borrowings as of September 30, 2011. If PECO lost its investment grade credit rating as of September 30, 2011, it would have been required to provide collateral of $7 million pursuant to PJM's credit policy and could have been required to provide collateral of $44 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.

Exelon Credit Facilities

Exelon and ComEd 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 7 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, revolving credit agreements and bilateral credit agreements at September 30, 2011:

Commercial Paper Programs

Commercial Paper Issuer	Maximum Program Size(a)	Outstanding Commercial Paper at September 30, 2011	Average Interest Rate on Commercial Paper Borrowings for the nine months ended September 30, 2011
Exelon Corporate	$ 500	$ 389	0.43%
Generation	5,600	73	0.47%
ComEd	1,000	—	0.72%
PECO	600	—	—

(a) Equals aggregate bank commitments under revolving credit agreements and bilateral credit agreements. See discussion and table below for items affecting effective program size.

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, 2011		Average Interest Rate on Facility Borrowings for nine months ended September 30, 2011
					Actual	To Support Additional Commercial Paper	
Exelon Corporate	Syndicated Revolver	$ 500	$ —	$ 7	$ 493	$ 103	—
Generation	Syndicated Revolver	5,300	—	13	5,287	5,215	—
Generation	Bilateral	300	—	115	185	185	—
ComEd	Syndicated Revolver	1,000	—	196(b)	804	804	—
PECO	Syndicated Revolver	600	—	1	599	599	—

(a) Excludes $94 million of credit facility agreements arranged with minority and community banks in October 2010, which are solely utilized to issue letters of credit. See Note 7 of the Combined Notes to the Consolidated Financial Statements for further information.

(b) During October 2011, ComEd released and cancelled $191 million in letters of credit previously supporting variable rate tax-exempt debt that was retired on October 12, 2011.

Borrowings under the revolving credit agreements bear interest at a rate based upon either the prime rate or at a fixed rate for a specified period based upon a LIBOR-based rate. The Exelon, Generation and PECO agreements provide for adders of up to 85 basis points for prime-based borrowings and adders of up to 185 basis points for LIBOR-based borrowings, based upon the credit rating of the borrower. At September 30, 2011, Exelon, Generation and PECO adders were 30, 30 and 10 basis points, respectively, for prime-based borrowings and 130, 130 and 110 basis points, respectively, for LIBOR-based borrowings. Under the ComEd agreement, adders of up to 137.5 basis points for prime-based borrowings and 237.5 basis points for LIBOR-based borrowings may be added based upon ComEd's credit rating. At September 30, 2011, ComEd's adder was 87.5 basis points for prime-based borrowings and 187.5 basis points for LIBOR-based borrowings.

Under Generation's bilateral credit agreement, Generation pays a facility fee, payable on the first day of each calendar quarter at a rate per annum equal to a specified facility fee rate on the total amount of the credit facility regardless of usage.

Each credit agreement 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 interest coverage ratios exclude revenues and interest expenses attributable to securitization debt, certain changes in working capital, distributions on preferred securities of subsidiaries and interest on nonrecourse debt. The following table summarizes the minimum thresholds reflected in the credit agreements for the nine months ended September 30, 2011:

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

At September 30, 2011, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO
Interest coverage ratio	16.13	29.50	7.18	8.19

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 interest on any indebtedness having a principal amount in excess of $100 million in the aggregate by Generation (including Generation's credit facility) will constitute an event of default under the Exelon credit facility.

Security Ratings

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

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

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. Refer to Note 6 of the Combined Notes to the Consolidated Financial Statements for additional information on collateral provisions.

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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, 2011, in addition to the net contribution or borrowing as of September 30, 2011, are presented in the following table:

	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Generation	$ —	$ 335	$ —
PECO	465	—	91
BSC	—	220	(94)
Exelon Corporate	261	N/A	3

Variable-Rate Debt

See Note 7 of the Combined Notes to the Consolidated Financial Statements for discussion regarding the Registrants' variable rate debt.

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 regards 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 regards to its 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 9 of the Combined Notes to the Consolidated Financial Statements for further information regarding the trust funds, the NRC's minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements

Each of the Registrants has 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 company, its securities ratings and market conditions.

Regulatory Authorizations

As of September 30, 2011, ComEd had $41 million available in long-term debt refinancing authority and $456 million available in new money long-term debt financing authority from the ICC, and PECO had $1.9 billion available in long-term debt financing authority from the PAPUC.

As of September 30, 2011, ComEd and PECO had short-term financing authority from FERC, which expires on December 31, 2011, of $2.5 billion and $1.5 billion, respectively. On September 16, 2011, ComEd and PECO filed applications with FERC for renewal of their short-term financing authorities through December 31, 2013. ComEd and PECO expect resolution of the applications before the end of the year.

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 13 of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' commitments.

Generation, ComEd and PECO have obligations related to contracts for the purchase of power and fuel supplies, and ComEd and PECO 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.

Antelope Valley Project Development Agreement

On September 30, 2011, the DOE issued a guarantee for up to $646 million for a non-recourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley solar facility. See Note 7 — Debt and Credit Agreements for additional information on the loan guaranteed by the DOE and Note 6 — Derivative Financial Instruments for additional information on the interest rate swap entered into in connection with the agreement.

EXELON GENERATION COMPANY

General

Generation operates in three segments: Mid-Atlantic, Midwest, and South and West. The operations of all three segments consist of owned and contracted electric generating facilities, wholesale energy marketing operations and competitive retail sales operations. These segments are discussed in further detail in "EXELON CORPORATION — General" of this Form 10-Q.

Executive Overview

A discussion of items pertinent to Generation's executive overview is set forth under "EXELON CORPORATION — Executive Overview" of this Form 10-Q.

Results of Operations

A discussion of items pertinent to Generation's results of operations for the three months ended September 30, 2011 compared to the three months ended September 30, 2010 and the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010 is set forth under "Results of Operations — Generation" in "EXELON CORPORATION — Results of Operations" of this Form 10-Q.

Liquidity and Capital Resources

Generation's business is capital intensive and requires considerable capital resources. Generation's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, participation in the intercompany money pool or capital contributions from Exelon. Generation's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where Generation no longer has access to the capital markets at reasonable terms, Generation has access to credit facilities of $5.6 billion that Generation currently utilizes to support its commercial paper program and to issue letters of credit.

See the “EXELON CORPORATION — Liquidity and Capital Resources” of this Form 10-Q for further discussion.

Capital resources are used primarily to fund Generation’s capital requirements, including construction, retirement of debt, the payment of distributions to Exelon, contributions to Exelon’s pension plans and investments in new and existing ventures. Future acquisitions could require external financing or borrowings or capital contributions from Exelon.

Cash Flows from Operating Activities

A discussion of items pertinent to Generation’s cash flows from operating activities is set forth under “Cash Flows from Operating Activities” in “EXELON CORPORATION — Liquidity and Capital Resources” of this Form 10-Q.

Cash Flows from Investing Activities

A discussion of items pertinent to Generation’s cash flows from investing activities is set forth under “Cash Flows from Investing Activities” in “EXELON CORPORATION — Liquidity and Capital Resources” of this Form 10-Q.

Cash Flows from Financing Activities

A discussion of items pertinent to Generation’s cash flows from financing activities is set forth under “Cash Flows from Financing Activities” in “EXELON CORPORATION — Liquidity and Capital Resources” of this Form 10-Q.

Credit Matters

A discussion of items pertinent to Generation’s credit facilities is set forth under “Credit Matters” in “EXELON CORPORATION — Liquidity and Capital Resources” of this Form 10-Q.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of items pertinent to Generation’s contractual obligations and off-balance sheet arrangements is set forth under “Other Purchase Obligations” in Note 13 of the Combined Notes to Consolidated Financial Statements.

COMMONWEALTH EDISON COMPANY

General

ComEd operates in a single operating segment and its operations consist 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.

Executive Overview

A discussion of items pertinent to ComEd’s executive overview is set forth under “EXELON CORPORATION — Executive Overview” of this Form 10-Q.

Results of Operations

A discussion of items pertinent to ComEd's results of operations for the three months ended September 30, 2011 compared to the three months ended September 30, 2010, and the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010, is set forth under "Results of Operations — ComEd" in "EXELON CORPORATION — Results of Operations" of this Form 10-Q.

Liquidity and Capital Resources

ComEd's business is capital intensive and requires considerable capital resources. ComEd's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of commercial paper, credit facility borrowings and the issuance of First Mortgage Bonds. ComEd's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where ComEd no longer has access to the capital markets at reasonable terms, ComEd has access to its revolving credit facility. At September 30, 2011, ComEd had access to a revolving credit facility with aggregate bank commitments of $1 billion.

See "EXELON CORPORATION — Liquidity and Capital Resources" and Note 7 of the Combined Notes to the Financial Statements of this Form 10-Q for further discussion.

Capital resources are used primarily to fund ComEd's capital requirements, including construction, retirement of debt, and contributions to Exelon's pension plans. Additionally, ComEd operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ComEd's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION — Liquidity and Capital Resources" of this Form 10-Q.

Cash Flows from Investing Activities

A discussion of items pertinent to ComEd's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION — Liquidity and Capital Resources" of this Form 10-Q.

Cash Flows from Financing Activities

A discussion of items pertinent to ComEd's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION — Liquidity and Capital Resources" of this Form 10-Q.

Credit Matters

A discussion of items pertinent to ComEd's credit facilities is set forth under "Credit Matters" in "EXELON CORPORATION — Liquidity and Capital Resources" of this Form 10-Q.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of items pertinent to ComEd's contractual obligations and off-balance sheet arrangements is set forth under "Other Purchase Obligations" in Note 13 of the Combined Notes to Consolidated Financial Statements.

PECO ENERGY COMPANY

General

PECO operates in two business segments that are aggregated into one reportable segment, and its operations consist 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 Pennsylvania in the counties surrounding the City of Philadelphia.

Executive Overview

A discussion of items pertinent to PECO's executive overview is set forth under "EXELON CORPORATION — Executive Overview" of this Form 10-Q.

Results of Operations

A discussion of items pertinent to PECO's results of operations for the three months ended September 30, 2011 compared to three months ended September 30, 2010 and nine months ended September 30, 2011 compared to nine months ended September 30, 2010 is set forth under "Results of Operations — PECO" in "EXELON CORPORATION — Results of Operations" of this Form 10-Q.

Liquidity and Capital Resources

PECO's business is capital intensive and requires considerable capital resources. PECO's capital resources are primarily provided by internally generated cash flows from operations, and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, accounts receivable agreement or participation in the intercompany money pool. PECO's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where PECO no longer has access to the capital markets at reasonable terms, PECO has access to a revolving credit facility. At September 30, 2011, PECO had access to a revolving credit facility with aggregate bank commitments of $600 million.

See "EXELON CORPORATION — Liquidity and Capital Resources" of this Form 10-Q for further discussion.

Capital resources are used primarily to fund PECO's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, PECO operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PECO's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION — Liquidity and Capital Resources" of this Form 10-Q.

Cash Flows from Investing Activities

A discussion of items pertinent to PECO's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION — Liquidity and Capital Resources" of this Form 10-Q.

Cash Flows from Financing Activities

A discussion of items pertinent to PECO's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION — Liquidity and Capital Resources" of this Form 10-Q.

Credit Matters

A discussion of items pertinent to PECO's credit facilities is set forth under "Credit Matters" in "EXELON CORPORATION — Liquidity and Capital Resources" of this Form 10-Q.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of items pertinent to PECO's contractual obligations and off-balance sheet arrangements is set forth under "Other Purchase Obligations" in Note 13 of the Combined Notes to Consolidated Financial Statements.

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 financial officer, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the Exelon Board of Directors on the scope of the risk management activities. The following discussion serves as an update to Item 7A-Quantitative and Qualitative Disclosures about Market Risk of the Registrants' 2010 Annual Report on Form 10-K incorporated herein by reference.

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

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 or contracted generation supply in excess of Generation's obligations to customers, including ComEd's and PECO'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 2011 through 2013. Generation's energy contracts are accounted for under the accounting guidance for derivatives as further discussed in Note 6 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, 2011, the percentage of expected generation hedged was 97%-100%, 85%-88%, and 56%-59% for 2011, 2012 and 2013, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include cash flow hedges, other derivatives and certain non-derivative contracts including sales to ComEd and PECO 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 Ni-Hub and PJM-West around-the-clock energy price based on September 30, 2011 market conditions and hedged position would be a decrease in pre-tax net income of approximately $4 million, $88 million and $349 million, respectively, for 2011, 2012 and 2013. 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 purely to profit from market price changes as opposed to hedging an exposure and is subject to limits established by Exelon's RMC. The trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 1,679 GWhs and 4,508 GWhs for the three and nine months ended September 30, 2011, respectively, and 1,077 GWhs and 2,885 GWhs for the three and nine months ended September 30, 2010, respectively, are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall revenue from energy marketing activities. Trading portfolio activity for the nine months ended September 30, 2011 resulted in pre-tax gains of $23 million due to net mark-to-market gains of $3 million and realized gains of $20 million. Generation uses a 95% confidence interval, one day holding period, one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $110,000 of exposure over the last 18 months. 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, 2011 of $5,124 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 2011 through 2015 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial positions. See Note 13 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.

ComEd's RFP contracts are deemed to be derivatives that qualify for the normal purchases and normal sales scope exceptions 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. For additional information on these contracts, see Note 6 of the Combined Notes to Consolidated Financial Statements.

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PECO

PECO procures electric supply for default service customers through block contracts and full requirements contracts pursuant to PECO's PAPUC-approved DSP Program. PECO's full requirements contracts and block contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance. Under the DSP Program, PECO is permitted to recover its electricity procurement costs from retail customers without mark-up.

PECO has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its long-term price risk in the natural gas market. 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.

PECO does not enter into derivatives for speculative or proprietary trading purposes.

For additional information on these contracts, see Note 6 of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities

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

The following table provides detail on changes in Exelon's, Generation's, ComEd's and PECO's mark-to-market net asset or liability balance sheet position from December 31, 2010 to September 30, 2011. 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. 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, 2011 and December 31, 2010 refer to Note 6 of the Combined Notes to Consolidated Financial Statements.

	Generation	ComEd	PECO	Intercompany Eliminations(e)	Exelon
Total mark-to-market energy contract net assets (liabilities) at December 31, 2010(a)	$ 1,803	$ (971)	$ (9)	$ —	$ 823
Total change in fair value during 2011 of contracts recorded in result of operations	35	—	—	—	35
Reclassification to realized at settlement of contracts recorded in results of operations	(391)	—	—	—	(391)
Ineffective portion recognized in income	(4)	—	—	—	(4)
Reclassification to realized at settlement from accumulated OCI(b)	(617)	—	—	312	(305)
Effective portion of changes in fair value — recorded in OCI(c)(f)	(109)	—	—	4	(105)
Changes in fair value — energy derivatives(d)	—	259	6	(316)	(51)
Changes in collateral	804	—	—	—	804
Changes in net option premium paid/(received)	(59)	—	—	—	(59)
Other income statement reclassifications(g)	(102)	—	—	—	(102)
Total mark-to-market energy contract net assets (liabilities) at September 30, 2011(a)	$ 1,360	$ (712)	$ (3)	$ —	$ 645

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) For Generation, includes $309 million and $3 million of losses from reclassifications from accumulated OCI to recognize gains in net income related to settlements of the five-year financial swap contract with ComEd and the PECO block contracts for the nine months ended September 30, 2011, respectively.
(c) For Generation, includes $4 million of losses related to the changes in fair value of the five-year financial swap with ComEd for the nine months ended September 30, 2011. The PECO block contracts were designated as normal in May 2010. As such, no additional changes in fair value of PECO's block contracts were recorded and the mark-to-market balances previously recorded are being amortized over the terms of the contracts.
(d) For ComEd and PECO, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of September 30, 2011, ComEd recorded $712 million of regulatory assets related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. As of September 30, 2011, this included increases of $4 million related to changes in fair value and increases of $309 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, 2011, ComEd also recorded a $54 million decrease in fair value associated with floating-to-fixed energy swap contracts with unaffiliated suppliers. As of September 30, 2011, PECO recorded $3 million of regulatory assets related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. As of September 30, 2011, this included increases of $3 million for reclassifications from regulatory asset to recognized cost in purchased power expense due to settlements of PECO's block contracts with Generation. The PECO block contracts were designated as normal purchases in May 2010. As such, no additional changes in fair value of PECO's block contracts were recorded and the mark-to-market balances previously recorded are being amortized over the terms of the contracts.
(e) Amounts related to the five-year financial swap between Generation and ComEd and the block contracts between Generation and PECO are eliminated in consolidation.
(f) For Generation, includes $4 million of changes in cash flow hedge ineffectiveness, none of which were related to Generation's financial swap contract with ComEd or Generation's block contracts with PECO.
(g) Includes $102 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, 2011.

Fair Values

The following table 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 5 of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2011	2012	2013	2014	2015	2016 and Beyond	Total Fair Value
Normal Operations, qualifying cash flow hedge contracts(a)(c):							
Prices provided by external sources	$170	$ 92	$ 21	$(25)	$—	$ —	$ 258
Total	$170	$ 92	$ 21	$(25)	$—	$ —	$ 258
Normal Operations, other derivative contracts(b)(c):							
Actively quoted prices	$ —	$ (1)	$ —	$ —	$—	$ —	$ (1)
Prices provided by external sources	128	118	106	58	3	—	413
Prices based on model or other valuation methods(d)	10	17	(14)	(13)	(7)	(18)	(25)
Total	$138	$134	$ 92	$ 45	$ (4)	$ (18)	$ 387

(a) Mark-to-market gains and losses on contracts that qualify as cash flow hedges are recorded in OCI.

(b) Mark-to-market gains and losses on other non-trading hedge and trading derivative contracts that do not qualify as cash flow hedges are recorded in results of operations.
(c) Amounts are shown net of collateral paid to and received from counterparties of $147 million at September 30, 2011.

Generation

	Maturities Within						
	2011	2012	2013	2014	2015	2016 and Beyond	Total Fair Value
Normal Operations, qualifying cash flow hedge contracts(a)(c):							
Prices provided by external sources	$170	$ 92	$ 21	$(25)	$—	$ —	$ 258
Prices based on model or other valuation methods	139	394	131	—	—	—	664
Total	$309	$486	$152	$(25)	$—	$ —	$ 922
Normal Operations, other derivative contracts(b)(c):							
Actively quoted prices	$ —	$ (1)	$ —	$ —	$—	$ —	$ (1)
Prices provided by external sources	128	118	106	58	3	—	413
Prices based on model or other valuation methods	11	24	(4)	(5)	(1)	1	26
Total	$139	$141	$102	$ 53	$ 2	$ 1	$ 438

(a) Mark-to-market gains and losses on contracts that qualify as cash flow hedges are recorded in OCI. Amounts include a $662 million gain associated with the five-year financial swap with ComEd and $2 million gain related to the fair value of the PECO block contracts.
(b) Mark-to-market gains and losses on other non-trading hedge and trading derivative contracts that do not qualify as cash flow hedges are recorded in results of operations.
(c) Amounts are shown net of collateral paid to and received from counterparties of $147 million at September 30, 2011.

ComEd

	Maturities Within						
	2011	2012	2013	2014	2015	2016 and beyond	Total Fair Value
Prices based on model or other valuation methods(a)	$(137)	$(401)	$(141)	$ (8)	(6)	$ (19)	$ (712)

(a) Represents ComEd's net assets (liabilities) associated with the five-year financial swap with Generation and the floating-to-fixed energy swap contracts with unaffiliated suppliers. $2 million expected to mature in 2012 is included within other current liabilities within ComEd's Consolidated Balance Sheets.

PECO

	Maturities Within						
	2011	2012	2013	2014	2015	2016 and Beyond	Total Fair Value
Prices based on model or other valuation methods(a)	$ (3)	$—	$—	$—	$—	$ —	$ (3)

(a) Represents PECO's net liabilities associated with its block contracts executed under its DSP Program. Includes $2 million related to PECO's block contracts with Generation. See Note 6 of the Combined Notes to Consolidated Financial Statements for information regarding the election of the normal purchases and normal sales scope exception for these contracts.

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

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 6 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, 2011. 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 and ICE commodity exchanges, which are discussed below. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd and PECO of $57 million and $38 million, respectively. See Note 21 of the 2010 Form 10-K for further information.

Rating as of September 30, 2011	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	$ 968	$ 167	$ 801	2	$ 192
Non-investment grade	10	3	7	—	—
No external ratings					
Internally rated — investment grade	35	7	28	—	—
Internally rated — non-investment grade	4	2	2	—	—
Total	$ 1,017	$ 179	$ 838	2	$ 192

	Maturity of Credit Risk Exposure			
Rating as of September 30, 2011	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 781	$ 136	$ 51	$ 968
Non-investment grade	10	—	—	10
No external ratings				
Internally rated — investment grade	31	4	—	35
Internally rated — non-investment grade	4	—	—	4
Total	$ 826	$ 140	$ 51	$ 1,017

Net Credit Exposure by Type of Counterparty	As of September 30, 2011
Financial institutions	$ 368
Investor-owned utilities, marketers and power producers	281
Energy cooperatives and municipalities	152
Other	37
Total	$ 838

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 2010 Annual Report on Form 10-K.

See Note 6 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 2010 Annual Report on Form 10-K.

See Note 6 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 financially settled contracts for the purchase and sale of capacity, energy, fuels, RECs and emissions allowances. 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, the obligation to supply the collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. If Generation can reasonably claim that it is willing and financially able to perform its obligations, it may be possible to successfully argue that no collateral should be posted or that only an amount equal to two or three months of future payments should be sufficient.

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, Exelon depends on access to bank credit lines which serve as liquidity sources to fund collateral requirements.

As of September 30, 2011, Generation had cash collateral deposit payments being held by counterparties of $71 million and Generation was holding $219 million of cash collateral deposits received from counterparties, of which $147 million of cash collateral deposits was offset against mark-to-market assets and liabilities. As of September 30, 2011, $1 million of cash collateral received was not offset against net derivatives positions, because they were not associated with energy-related derivatives. See Note 13 of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of September 30, 2011, 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, 2011, PECO was not required to post, nor does it hold collateral under its electric and natural gas procurement contracts. See to Note 6 — Derivative Financial Instruments for further discussion.

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

Generation, ComEd and PECO 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. and the Electric Reliability Council of Texas. 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 and ICE. The NYMEX and ICE clearinghouses act as the counterparty to each trade. Transactions on NYMEX and ICE must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX and ICE are significantly collateralized and have limited counterparty credit risk.

Long-Term Leases (Exelon)

Exelon's consolidated balance sheets, as of September 30, 2011, included a $649 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 $843 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms which are set at prices above expected fair market value of the plants at lease inception. 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 and PECO)

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 to adjust exposure based upon market conditions. 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 risks. At September 30, 2011, Exelon had $100 million of notional amounts of fair value hedges outstanding.

A hypothetical 10% increase in the interest rates associated with variable-rate debt would result in less than a $1 million decrease in Exelon's, ComEd's and PECO's pre-tax earnings for the nine months ended September 30, 2011. This calculation holds all other variable 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, 2011, 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 $319 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 2011, each of Exelon's, Generation's, ComEd's and PECO'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 each of Exelon, Generation, ComEd and PECO 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, 2011, the principal executive officer and principal financial officer of each of Exelon, Generation, ComEd and PECO concluded that such Registrant's disclosure controls and procedures were effective to accomplish its objectives. Exelon, Generation, ComEd and PECO 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 2011 that have materially affected, or are reasonably likely to materially affect, each of Exelon's, Generation's, ComEd's and PECO'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' 2010 Form 10-K and (b) Notes 3, 4 and 13 of the Combined Notes to Consolidated Financial Statements in Part I, Item 1 of this Report. Such descriptions are incorporated herein by these references.

Item 1A. Risk Factors

Risks Related to Exelon

Exelon is, and will continue to be, subject to the risks described in Exelon's 2010 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 — Commitments and Contingencies. As a result of the merger agreement announced with Constellation on April 28, 2011, Exelon is subject to additional risks related to the merger as described below.

Risks Related to the Proposed Merger with Constellation

Because the market price of shares of Exelon common stock will fluctuate and the exchange ratio will not be adjusted to reflect such fluctuations, the merger consideration at the date of the closing may vary significantly from the date the merger agreement was executed.

Upon completion of the merger, each outstanding share of Constellation common stock will be converted into the right to receive 0.930 of a share of Exelon common stock. The number of shares of Exelon common stock to be issued pursuant to the merger agreement for each share of Constellation common stock will not change to reflect changes in the market price of Exelon or Constellation common stock. The market price of Exelon common stock at the time of completion of the merger may vary significantly from the market prices of Exelon common stock on the date the merger agreement was executed.

In addition, Exelon might not complete the merger until a significant period of time has passed after the respective special shareholder meetings. Because Exelon will not adjust the exchange ratio to reflect any changes in the market value of Exelon common stock or Constellation common stock, the market value of the Exelon common stock issued in connection with the merger and the Constellation common stock surrendered in connection with the merger may be higher or lower than the values of those shares on earlier dates. Stock price changes may result from market reaction to the announcement of the merger and market assessment of the likelihood that the merger will be completed, changes in the business, operations or prospects of Exelon or Constellation prior to or following the merger, litigation or regulatory considerations, general business, market, industry or economic conditions and other factors both within and beyond the control of Exelon and Constellation. Neither Exelon nor Constellation is permitted to terminate the merger agreement solely because of changes in the market price of either company's common stock.

The merger agreement contains provisions that limit each of Exelon's and Constellation's ability to pursue alternatives to the merger, which could discourage a potential acquirer of either Constellation or Exelon from making an alternative transaction proposal and, in certain circumstances, could require Exelon or Constellation to pay to the other a significant termination fee.

Under the merger agreement, Exelon and Constellation are restricted, subject to limited exceptions, from entering into alternative transactions in lieu of the merger. In general, unless and until the merger agreement is terminated, both Exelon and Constellation are restricted from, among other things, soliciting, initiating, knowingly encouraging or facilitating a competing acquisition proposal from any person. Each of the Exelon board of directors and the Constellation board of directors is limited in its ability to change its recommendation with respect to the merger-related proposals. Exelon or Constellation may terminate the merger agreement and enter into an agreement with respect to a superior proposal only if specified conditions have been satisfied, including compliance with the non-solicitation provisions of the merger agreement. These provisions could discourage a third party that may have an interest in acquiring all or a significant part of Exelon or Constellation from considering or proposing such an acquisition, even if such third party were prepared to pay consideration with a higher per share cash or market value than the consideration proposed to be received or realized in the merger, or might result in a potential competing acquirer proposing to pay a lower price than it would otherwise have proposed to pay because of the added expense of the termination fee that may become payable in certain circumstances. Under the merger agreement, in the event Exelon or Constellation terminates the merger agreement to accept a superior proposal, or under certain other circumstances, Exelon or Constellation, as applicable, would be required to pay a termination fee of $800 million in the case of a termination fee payable by Exelon to Constellation and a termination fee of $200 million in the case of a termination fee payable by Constellation to Exelon.

Exelon and Constellation will be subject to various uncertainties and contractual restrictions while the merger is pending that may cause disruption and could adversely affect their financial results.

Uncertainty about the effect of the merger on employees, suppliers and customers may have an adverse effect on Exelon and/or Constellation. These uncertainties may impair Exelon's and/or Constellation's ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, as employees and prospective employees may experience uncertainty about their future roles with the combined company, and could cause customers, suppliers and others who deal with Exelon or Constellation to seek to change existing business relationships with Exelon or Constellation. The pursuit of the merger and the preparation for the integration may also place a burden on management and internal resources. Any significant diversion of management attention away from ongoing business concerns and any difficulties encountered in the transition and integration process could affect Exelon's and/or Constellation's financial results.

In addition, the merger agreement restricts each of Exelon and Constellation, without the other's consent, from making certain acquisitions and taking other specified actions while the merger is pending. These restrictions may prevent Exelon and/or Constellation from pursuing otherwise attractive business opportunities and making other changes to their respective businesses prior to completion of the merger or termination of the merger agreement.

If completed, the merger may not achieve its anticipated results, and Exelon and Constellation may be unable to integrate their operations 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 each company's ongoing 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. The combined company's results of operations could also be adversely affected by any issues attributable to either company's operations that arise or are based on events or actions that occur prior to the closing of the merger. The companies 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 the combined company'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 is expected to 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.

Exelon may record goodwill that could become impaired and adversely affect its operating results.

Accounting standards in the United States require that one party to the merger be identified as the acquirer. In accordance with these standards, the merger will be accounted for as an acquisition of Constellation common stock by Exelon and will follow the acquisition method of accounting for business combinations. The assets and liabilities of Constellation will be consolidated with those of Exelon. The excess of the purchase price over the fair values of Constellation's assets and liabilities, if any, will be recorded as goodwill.

The amount of goodwill, which could be material, will be allocated to the appropriate reporting units of the combined company. Exelon is required to assess goodwill for impairment at least annually by comparing the fair value of reporting units to the carrying value of those reporting units. To the extent the carrying value of any of those reporting units is greater than the fair value, a second step comparing the implied fair value of goodwill to the carrying amount would be required to determine if the goodwill is impaired. Such a potential impairment could result in a material charge that would have a material impact on Exelon's future operating results and consolidated balance sheet.

The merger is subject to the receipt of consent or approval from governmental entities that could delay the completion of the merger or impose conditions or require additional concessions that could have a material adverse effect on the combined company or that could cause abandonment of the merger.

Completion of the merger is conditioned upon the receipt of consents, orders, approvals or clearances, to the extent required, from the FERC, the NRC, the FCC, and the public utility commissions or similar entities in certain states in which the companies operate, including the Maryland Public Service Commission. The merger is also subject to review by the DOJ Antitrust Division, under the HSR Act, and the expiration or earlier termination of the waiting period (and any extension of the waiting period) applicable to the merger is a condition to closing the merger. The special meetings of the shareholders of Exelon and Constellation at which the proposals required to complete the merger will be considered may take place before any or all of the required regulatory approvals have been obtained and before all conditions to such approvals, if any, are known.

In this event, if the shareholder proposals required to complete the merger are approved, Exelon and Constellation may subsequently agree to conditions or offer additional concessions without seeking further shareholder approval, even if such conditions and concessions could have an adverse effect on Exelon, Constellation or the combined company.

Exelon and Constellation cannot provide assurance that we will obtain all required regulatory consents or approvals or that these consents or approvals will not contain terms, conditions or restrictions that would be detrimental to the combined company after the completion of the merger. In addition, Exelon and Constellation recognize that government officials may seek concessions in excess of those announced by the parties and included in their regulatory filings. The merger agreement generally permits each party to terminate the merger agreement if the final terms of any of the required regulatory consents or approvals require (1) any action that involves divesting, holding separate or otherwise transferring control over any nuclear or hydroelectric or pumped-storage generation assets of the parties or any of their respective subsidiaries or affiliates; or (2) any action (including any action that involves divesting, holding separate or otherwise transferring control over base-load capacity), without including those actions proposed by the parties' mutually agreed-upon analysis of mitigation to address the increased market concentration resulting from the merger and the concessions announced by the parties in the press release announcing the merger agreement, which would, individually or in the aggregate, reasonably be expected to have a material adverse effect on either party. Any substantial delay in obtaining satisfactory approvals, receipt of proceeds from required divestitures in an amount substantially lower than anticipated or the imposition of any terms or conditions or the offer of additional concessions in connection with such approvals could cause a material reduction in the expected benefits of the merger. If any such delays or conditions are serious enough, the parties may decide to abandon the merger.

Exelon cannot assure that it will be able to continue paying dividends at the current rate.

Exelon currently expects to pay dividends in an amount consistent with the dividend policy of Exelon in effect prior to the completion of the merger. However, there is no assurance that Exelon shareholders will receive the same dividends following the merger for reasons that may include any of the following factors:

- Exelon may not have enough cash to pay such dividends due to changes in Exelon's cash requirements, capital spending plans, financing agreements, cash flow or financial position;
- decisions on whether, when and in which amounts to make any future distributions will remain at all times entirely at the discretion of the Exelon board of directors, which reserves the right to change Exelon's dividend practices at any time and for any reason;
- the amount of dividends that Exelon may distribute to its shareholders is subject to restrictions under Pennsylvania law; and
- Exelon may not receive dividend payments from its subsidiaries in the same level that it has historically. The ability of Exelon's subsidiaries to make dividend payments to it is subject to factors similar to those listed above.

Exelon's shareholders should be aware that they have no contractual or other legal right to dividends that have not been declared.

If completed, the merger may adversely affect the combined company's ability to attract and retain key employees.

Current and prospective Exelon and Constellation employees may experience uncertainty about their future roles at the combined company following the completion of the proposed merger. In addition, current and prospective Exelon and 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 the combined company's ability to attract and retain key management and other personnel.

Failure to complete the merger could negatively affect the share prices and the future businesses and financial results of Exelon and Constellation.

Completion of the merger is not assured and is subject to risks, including the risks that approval of the transaction by shareholders of Exelon and Constellation or by governmental agencies will not be obtained or that certain other closing conditions will not be satisfied. If the merger is not completed, the ongoing businesses of Exelon or Constellation may be adversely affected and Exelon and Constellation will be subject to several risks, including:

- having to pay certain significant costs relating to the merger without receiving the benefits of the merger, including, in certain circumstances, a termination fee of $800 million in the case of a termination fee payable by Exelon to Constellation and a termination fee of $200 million in the case of a termination fee payable by Constellation to Exelon;

- the potential loss of key personnel during the pendency of the merger as employees may experience uncertainty about their future roles with the combined company;
- Exelon and Constellation will have been subject to certain restrictions on the conduct of their businesses, which may have prevented them from making certain acquisitions or dispositions or pursuing certain business opportunities while the merger is pending; and
- the share price of Exelon or Constellation may decline to the extent that the current market prices reflect an assumption by the market that the merger will be completed.

Exelon and Constellation may incur unexpected transaction fees and merger-related costs in connection with the merger.

Exelon and Constellation expect to incur a number of non-recurring expenses, totalling approximately $144 million, associated with completing the merger, as well as expenses related to combining the operations of the two companies. The combined company 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.

Current Exelon shareholders and Constellation stockholders will have a reduced ownership and voting interest after the merger.

Exelon will issue or reserve for issuance approximately 201.9 million shares of Exelon common stock to Constellation stockholders in the merger (including shares of Exelon common stock issuable pursuant to Constellation stock options and other equity-based awards). Based on the number of shares of common stock of Exelon and Constellation outstanding on March 31, 2011, the record date for the two companies' special meetings of shareholders, upon the completion of the merger, current Exelon shareholders and former Constellation stockholders would own approximately 78% and 22% of the outstanding shares of Exelon common stock, respectively, immediately following the consummation of the merger.

Exelon shareholders and Constellation stockholders currently have the right to vote for their respective directors and on other matters affecting their company. When the merger occurs, each Constellation stockholder who receives shares of Exelon common stock will become a shareholder of Exelon with a percentage ownership of the combined company that will be smaller than the shareholder's percentage ownership of Constellation.

Correspondingly, each Exelon shareholder will remain a shareholder of Exelon with a percentage ownership of the combined company that will be smaller than the shareholder's percentage of Exelon prior to the merger. As a result of these reduced ownership percentages, Exelon shareholders will have less voting power in the combined company than they now have with respect to Exelon, and former Constellation stockholders will have less voting power in the combined company than they now have with respect to Constellation.

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Item 6. Exhibits

Exhibit No.	Description
4-1	Supplemental Indenture dated as of August 22, 2011 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 September 7, 2011, 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

* In accordance with Regulation S-T, the XBRL-related information in Exhibit 101 to this Quarterly Report on Form 10-Q shall be deemed to be “furnished” and not “filed”.

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, 2011 filed by the following officers for the following companies:

31-1	— Filed by John W. Rowe for Exelon Corporation
31-2	— Filed by Matthew F. Hilzinger for Exelon Corporation
31-3	— Filed by John W. Rowe for Exelon Generation Company, LLC
31-4	— Filed by Matthew F. Hilzinger for Exelon Generation Company, LLC
31-5	— Filed by Frank M. Clark for Commonwealth Edison Company
31-6	— Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
31-7	— Filed by Denis P. O’Brien for PECO Energy Company
31-8	— Filed by Phillip S. Barnett for PECO Energy 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, 2011 filed by the following officers for the following companies:

32-1	— Filed by John W. Rowe for Exelon Corporation
32-2	— Filed by Matthew F. Hilzinger for Exelon Corporation
32-3	— Filed by John W. Rowe for Exelon Generation Company, LLC
32-4	— Filed by Matthew F. Hilzinger for Exelon Generation Company, LLC
32-5	— Filed by Frank M. Clark for Commonwealth Edison Company
32-6	— Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
32-7	— Filed by Denis P. O’Brien for PECO Energy Company
32-8	— Filed by Phillip S. Barnett for PECO Energy 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/ JOHN W. ROWE	/s/ MATTHEW F. HILZINGER
John W. Rowe Chairman and Chief Executive Officer (Principal Executive Officer)	Matthew F. Hilzinger Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ DUANE M. DESPARTE	
Duane M. DesParte Vice President and Corporate Controller (Principal Accounting Officer)	

October 26, 2011

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/ JOHN W. ROWE	/s/ MATTHEW F. HILZINGER
John W. Rowe Chairman (Principal Executive Officer)	Matthew F. Hilzinger Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ MATTHEW R. GALVANONI	
Matthew R. Galvanoni Chief Accounting Officer (Principal Accounting Officer)	

October 26, 2011

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/ FRANK M. CLARK	/s/ ANNE R. PRAMAGGIORE
Frank M. Clark Chairman and Chief Executive Officer (Principal Executive Officer)	Anne R. Pramaggiore President and Chief Operating Officer
/s/ JOSEPH R. TRPIK, JR.	/s/ KEVIN J. WADEN
Joseph R. Trpik, Jr. Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	Kevin J. Waden Vice President and Controller (Principal Accounting Officer)

October 26, 2011

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/ DENIS P. O'BRIEN	/s/ PHILLIP S. BARNETT
Denis P. O'Brien Chief Executive Officer and President (Principal Executive Officer)	Phillip S. Barnett Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ JORGE A. ACEVEDO	
Jorge A. Acevedo Vice President and Controller (Principal Accounting Officer)	

October 26, 2011

Exhibit 31-1

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, John W. Rowe, 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/ JOHN W. ROWE

Chairman and Chief Executive Officer
(Principal Executive Officer)

Date: October 26, 2011

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Matthew F. Hilzinger, 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/ MATTHEW F. HILZINGER
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: October 26, 2011

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, John W. Rowe, 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/ JOHN W. ROWE
Chairman
(Principal Executive Officer)

Date: October 26, 2011

Exhibit 31-4

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Matthew F. Hilzinger, 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/ MATTHEW F. HILZINGER

Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: October 26, 2011

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Frank M. Clark, 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/ FRANK M. CLARK

Chairman and Chief Executive Officer
(Principal Executive Officer)

Date: October 26, 2011

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: October 26, 2011

Exhibit 31-7

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Denis P. O'Brien, 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/ DENIS P. O'BRIEN
Chief Executive Officer and President
(Principal Executive Officer)

Date: October 26, 2011

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 and Chief Financial Officer (Principal Financial Officer)

Date: October 26, 2011

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, 2011, 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/ JOHN W. ROWE

John W. Rowe
Chairman and Chief Executive Officer

Date: October 26, 2011

Exhibit 32-2

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Corporation for the quarterly period ended September 30, 2011, 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/ MATTHEW F. HILZINGER

Matthew F. Hilzinger
Senior Vice President, Chief Financial Officer and Treasurer

Date: October 26, 2011

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, 2011, 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/ JOHN W. ROWE

John W. Rowe
Chairman
(Principal Executive Officer)

Date: October 26, 2011

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, 2011, 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/ MATTHEW F. HILZINGER

Matthew F. Hilzinger
Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: October 26, 2011

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, 2011, 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/ FRANK M. CLARK

Frank M. Clark
Chairman and Chief Executive Officer

Date: October 26, 2011

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, 2011, 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: October 26, 2011

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, 2011, 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/ DENIS P. O'BRIEN

Denis P. O'Brien
Chief Executive Officer and President

Date: October 26, 2011

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, 2011, 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 and Chief Financial Officer

Date: October 26, 2011