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 quarter ended September 30, 2013

Commission File Number	Exact Name of Registrant as specified in its Charter, State or Other Jurisdiction of Incorporation, Address of Principal Executive Offices, Zip Code and Telephone Number (Including Area Code)	I.R.S. Employer Identification Number
001-31403	**PEPCO HOLDINGS, INC.** (Pepco Holdings or PHI), a Delaware corporation 701 Ninth Street, N.W. Washington, D.C. 20068 Telephone: (202)872-2000	52-2297449
001-01072	**POTOMAC ELECTRIC POWER COMPANY** (Pepco), a District of Columbia and Virginia corporation 701 Ninth Street, N.W. Washington, D.C. 20068 Telephone: (202)872-2000	53-0127880
001-01405	**DELMARVA POWER & LIGHT COMPANY** (DPL), a Delaware and Virginia corporation 500 North Wakefield Drive Newark, DE 19702 Telephone: (202)872-2000	51-0084283
001-03559	**ATLANTIC CITY ELECTRIC COMPANY** (ACE), a New Jersey corporation 500 North Wakefield Drive Newark, DE 19702 Telephone: (202)872-2000	21-0398280

Indicate by check mark whether each 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 and (2) has been subject to such filing requirements for the past 90 days.

Pepco Holdings	Yes ☒	No ☐	Pepco	Yes ☒	No ☐
DPL	Yes ☒	No ☐	ACE	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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Pepco Holdings	Yes ☒	No ☐	Pepco	Yes ☒	No ☐
DPL	Yes ☒	No ☐	ACE	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 the definitions 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
Pepco Holdings	☒	☐	☐	☐
Pepco	☐	☐	☒	☐
DPL	☐	☐	☒	☐
ACE	☐	☐	☒	☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Pepco Holdings	Yes ☐	No ☒	Pepco	Yes ☐	No ☒
DPL	Yes ☐	No ☒	ACE	Yes ☐	No ☒

Pepco, DPL, and ACE meet the conditions set forth in General Instruction H(1)(a) and (b) of Form 10-Q and are therefore filing this Form 10-Q with reduced disclosure format specified in General Instruction H(2) of Form 10-Q.

Registrant	Number of Shares of Common Stock of the Registrant Outstanding at October 24, 2013
Pepco Holdings	249,756,730 ($.01 par value)
Pepco	100 ($.01 par value) (a)
DPL	1,000 ($2.25 par value) (b)
ACE	8,546,017 ($3.00 par value) (b)

(a) All voting and non-voting common equity is owned by Pepco Holdings.
(b) All voting and non-voting common equity is owned by Conectiv, LLC, a wholly owned subsidiary of Pepco Holdings.

THIS COMBINED FORM 10-Q IS SEPARATELY FILED BY PEPCO HOLDINGS, PEPCO, DPL, AND ACE. INFORMATION CONTAINED HEREIN RELATING TO ANY INDIVIDUAL REGISTRANT IS FILED BY SUCH REGISTRANT ON ITS OWN BEHALF. EACH REGISTRANT MAKES NO REPRESENTATION AS TO INFORMATION RELATING TO THE OTHER REGISTRANTS.

TABLE OF CONTENTS

GLOSSARY OF TERMS

Term	Definition
2012 Form 10-K	The Annual Report on Form 10-K for the year ended December 31, 2012, as revised in PHI's Form 8-K dated August 30, 2013, for each Reporting Company, as applicable
ACE	Atlantic City Electric Company
ACE Funding	Atlantic City Electric Transition Funding LLC
AFUDC	Allowance for funds used during construction
AMI	Advanced metering infrastructure
AOCL	Accumulated Other Comprehensive Loss
ASC	Accounting Standards Codification
BGE	Baltimore Gas and Electric Company
BGS	Basic Generation Service (the supply of electricity by ACE to retail customers in New Jersey who have not elected to purchase electricity from a competitive supplier)
Bondable Transition Property	The principal and interest payments on the Transition Bonds and related taxes, expenses and fees
BSA	Bill Stabilization Adjustment
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
Conectiv	Conectiv, LLC, a wholly owned subsidiary of PHI and the parent of DPL and ACE
Contract EDCs	Pepco, DPL and BGE, the Maryland utilities required by the MPSC to enter into a contract for new generation
CSA	Credit Support Annex
CTA	Consolidated tax adjustment
CWIP	Construction work in progress
DC Undergrounding Task Force	The District of Columbia Mayor's Power Line Undergrounding Task Force
DCPSC	District of Columbia Public Service Commission
DDOE	District of Columbia Department of the Environment
Default Electricity Supply	The supply of electricity by PHI's electric utility subsidiaries at regulated rates to retail customers who do not elect to purchase electricity from a competitive supplier, and which, depending on the jurisdiction, is also known as Standard Offer Service or BGS
Default Electricity Supply Revenue	Revenue primarily from Default Electricity Supply
DOE	U.S. Department of Energy
DPL	Delmarva Power & Light Company
DPSC	Delaware Public Service Commission
EDCs	Electric distribution companies
EmPower Maryland	A Maryland demand-side management program for Pepco and DPL
Energy Services	Energy savings performance contracting services provided principally to federal, state and local government customers, and designing, constructing and operating combined heat and power, and central energy plants by Pepco Energy Services
EPA	U.S Environmental Protection Agency
EPS	Earnings per share
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FLRP	Forward Looking Rate Plan filed by DPL in Delaware
GAAP	Accounting principles generally accepted in the United States of America
GCR	Gas Cost Rate
GWh	Gigawatt hour
IMU	Interface management unit
IRS	Internal Revenue Service
ISDA	International Swaps and Derivatives Association
ISRA	New Jersey's Industrial Site Recovery Act
LIBOR	London Interbank Offered Rate

Term	Definition
Main Extension Rules	NJBPU rules regarding service extensions to certain areas described as "Areas Not Designated for Growth"
MAPP	Mid-Atlantic Power Pathway
Market Transition Charge Tax	Revenue ACE receives and pays to ACE Funding to recover income taxes associated with Transition Bond Charge revenue
MDC	MDC Industries, Inc.
MFVRD	Modified fixed variable rate design
MMBtu	One Million British Thermal units
MPSC	Maryland Public Service Commission
MW	Megawatt
MWh	Megawatt hour
NJBPU	New Jersey Board of Public Utilities
NJ SOCA Law	The New Jersey law under which the SOCAs were established
NOAA	National Oceanic and Atmospheric Administration
NUGs	Non-utility generators
NYMEX	New York Mercantile Exchange
OAL	New Jersey Office of Administrative Law
OPC	Office of People's Counsel
PCI	Potomac Capital Investment Corporation and its subsidiaries
Pepco	Potomac Electric Power Company
Pepco Energy Services	Pepco Energy Services, Inc. and its subsidiaries
Pepco Holdings or PHI	Pepco Holdings, Inc.
PHI Retirement Plan	PHI's noncontributory retirement plan
PJM	PJM Interconnection, LLC
PJM RTO	PJM regional transmission organization
Power Delivery	PHI's Power Delivery Business
PPA	Power purchase agreement
PRP	Potentially responsible party
PUHCA 2005	Public Utility Holding Company Act of 2005
RECs	Renewable energy credits
Regulated T&D Electric Revenue	Revenue from the transmission and the distribution of electricity to PHI's customers within its service territories at regulated rates
Reporting Company	PHI, Pepco, DPL or ACE
RI/FS	Remedial investigation and feasibility study
RIM	Reliability investment recovery mechanism
ROE	Return on equity
RPS	Renewable Energy Portfolio Standards
SEC	Securities and Exchange Commission
SEP	Supplemental Environmental Project
SOCAs	Standard Offer Capacity Agreements required to be entered into by ACE pursuant to a New Jersey law enacted to promote the construction of qualified electric generation facilities in New Jersey
SOS	Standard Offer Service, how Default Electricity Supply is referred to in Delaware, the District of Columbia and Maryland
SRECs	Solar renewable energy credits
Transition Bond Charge	Revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees
Transition Bonds	Transition Bonds issued by ACE Funding

FORWARD-LOOKING STATEMENTS

Some of the statements contained in this Quarterly Report on Form 10-Q with respect to Pepco Holdings, Inc. (PHI or Pepco Holdings), Potomac Electric Power Company (Pepco), Delmarva Power & Light Company (DPL) and Atlantic City Electric Company (ACE), including each of their respective subsidiaries, are forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act), and Section 27A of the Securities Act of 1933, as amended, and are subject to the safe harbor created thereby under the Private Securities Litigation Reform Act of 1995. These statements include declarations regarding the intents, beliefs, estimates and current expectations of one or more of PHI, Pepco, DPL or ACE (each, a Reporting Company) or their subsidiaries. In some cases, you can identify forward-looking statements by terminology such as "may," "might," "will," "should," "could," "expects," "intends," "assumes," "seeks to," "plans," "anticipates," "believes," "projects," "estimates," "predicts," "potential," "future," "goal," "objective," or "continue" or the negative of such terms or other variations thereof or comparable terminology, or by discussions of strategy that involve risks and uncertainties. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause one or more Reporting Companies' or their subsidiaries' actual results, levels of activity, performance or achievements to be materially different from any future results, levels of activity, performance or achievements expressed or implied by such forward-looking statements. Therefore, forward-looking statements are not guarantees or assurances of future performance, and actual results could differ materially from those indicated by the forward-looking statements.

The forward-looking statements contained herein are qualified in their entirety by reference to the following important factors, which are difficult to predict, contain uncertainties, are beyond each Reporting Company's or its subsidiaries' control and may cause actual results to differ materially from those contained in forward-looking statements:

- Changes in governmental policies and regulatory actions affecting the energy industry or one or more of the Reporting Companies specifically, including allowed rates of return, industry and rate structure, acquisition and disposal of assets and facilities, operation and construction of transmission and distribution facilities and the recovery of purchased power expenses;
- The outcome of pending and future rate cases and other regulatory proceedings, including (i) challenges to the base return on equity (ROE) and the application of the formula rate process for transmission services provided by Pepco, DPL and ACE; (ii) challenges raised in Pepco's and DPL's Federal Energy Regulatory Commission (FERC) proceeding seeking, among other things, recovery of all prudently incurred Mid-Atlantic Power Pathway (MAPP) abandoned costs and the full ROE previously approved by FERC with respect to such costs; (iii) challenges to DPL's 2011 and 2012 annual FERC formula rate updates; and (iv) other possible disallowances of recovery of costs and expenses;
- The resolution of outstanding tax matters with the Internal Revenue Service (IRS), and the funding of any additional taxes, interest or penalties that may be due;
- The expenditures necessary to comply with regulatory requirements, including regulatory orders, and to implement reliability enhancement, emergency response and customer service improvement programs;
- Possible fines, penalties or other sanctions assessed by regulatory authorities against a Reporting Company or its subsidiaries;
- The impact of adverse publicity and media exposure which could render one or more Reporting Companies or their subsidiaries vulnerable to negative customer perception and could lead to increased regulatory oversight or other sanctions;
- Weather conditions affecting usage and emergency restoration costs;
- Population growth rates and changes in demographic patterns;

- Changes in customer energy demand due to, among other things, conservation measures and the use of renewable energy and other energy-efficient products, as well as the impact of net metering and other issues associated with the deployment of distributed generation technologies;
- General economic conditions, including the impact of an economic downturn or recession on energy usage;
- Changes in and compliance with environmental and safety laws and policies;
- Changes in tax rates or policies;
- Changes in rates of inflation;
- Changes in accounting standards or practices;
- Unanticipated changes in operating expenses and capital expenditures;
- Rules and regulations imposed by, and decisions of, federal and/or state regulatory commissions, PJM Interconnection, LLC (PJM), the North American Electric Reliability Corporation and other applicable electric reliability organizations;
- Legal and administrative proceedings (whether civil or criminal) and settlements that affect a Reporting Company's or its subsidiaries' business and profitability;
- Pace of entry into new markets;
- Interest rate fluctuations and the impact of credit and capital market conditions on the ability to obtain funding on favorable terms; and
- Effects of geopolitical and other events, including the threat of domestic terrorism or cyber attacks.

These forward-looking statements are also qualified by, and should be read together with, the risk factors and other statements in each Reporting Company's annual report on Form 10-K for the year ended December 31, 2012, as revised in PHI's Form 8-K dated August 30, 2013, (2012 Form 10-K), as filed with the Securities and Exchange Commission (SEC), and in this Form 10-Q, and investors should refer to such risk factors and other statements in evaluating the forward-looking statements contained in this Quarterly Report on Form 10-Q.

Any forward-looking statements speak only as to the date this Quarterly Report on Form 10-Q for each Reporting Company was filed with the SEC and none of the Reporting Companies undertakes an obligation to update any forward-looking statements to reflect events or circumstances after the date on which such statements are made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for a Reporting Company to predict all such factors. Furthermore, it may not be possible to assess the impact of any such factor on such Reporting Company's or its subsidiaries' business (viewed independently or together with the business or businesses of some or all of the other Reporting Companies or their subsidiaries), or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. The foregoing factors should not be construed as exhaustive.

PART I FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

Listed below is a table that sets forth, for each registrant, the page number where the information is contained herein.

* Pepco and DPL have no operating subsidiaries and, therefore, their financial statements are not consolidated.

PEPCO HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME (LOSS)
(Unaudited)

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
	(millions of dollars, except per share data)			
Operating Revenue	$ 1,344	$ 1,389	$ 3,575	$ 3,569
Operating Expenses				
Fuel and purchased energy	579	648	1,587	1,658
Other services cost of sales	37	38	112	132
Other operation and maintenance	208	228	647	668
Depreciation and amortization	124	122	352	343
Other taxes	119	121	325	330
Deferred electric service costs	42	29	39	(6)
Impairment losses	—	2	—	5
Total Operating Expenses	1,109	1,188	3,062	3,130
Operating Income	235	201	513	439
Other Income (Expenses)				
Interest expense	(68)	(66)	(205)	(190)
Other income	8	9	24	27
Total Other Expenses	(60)	(57)	(181)	(163)
Income from Continuing Operations Before Income Tax Expense	175	144	332	276
Income Tax Expense Related to Continuing Operations	65	57	280	92
Net Income from Continuing Operations	110	87	52	184
Income (Loss) from Discontinued Operations, Net of Income Taxes	8	25	(322)	58
Net Income (Loss)	$ 118	$ 112	$ (270)	$ 242
Basic and Diluted Share Information				
Weighted average shares outstanding – Basic (millions)	249	229	245	228
Weighted average shares outstanding – Diluted (millions)	249	231	245	229
Earnings per share of common stock from Continuing Operations – Basic and Diluted	$ 0.44	$ 0.38	$ 0.21	$ 0.80
Earnings (Loss) per share of common stock from Discontinued Operations – Basic and Diluted	0.04	0.11	(1.31)	0.26
Basic and Diluted earnings (loss) per share	$ 0.48	$ 0.49	$ (1.10)	$ 1.06

The accompanying Notes are an integral part of these Consolidated Financial Statements.

PEPCO HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(millions of dollars)			
Net Income (Loss)	$ 118	$ 112	$ (270)	$ 242
Other Comprehensive Income from Continuing Operations				
Loss on treasury rate locks reclassified into income	—	1	1	1
Pension and other postretirement benefit plans	1	1	2	(4)
Other comprehensive income (loss), before income taxes	1	2	3	(3)
Income tax expense (benefit) related to other comprehensive income	—	2	1	(1)
Other comprehensive income (loss) from continuing operations, net of income taxes	1	—	2	(2)
Other Comprehensive Income from Discontinued Operations, Net of Income Taxes	—	4	6	18
Comprehensive Income (Loss)	$ 119	$ 116	$ (262)	$ 258

The accompanying Notes are an integral part of these Consolidated Financial Statements.

PEPCO HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2013	December 31, 2012
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 58	$ 25
Restricted cash equivalents	15	10
Accounts receivable, less allowance for uncollectible accounts of $41 million and $34 million, respectively	844	804
Inventories	169	153
Prepayments of income taxes	41	59
Deferred income tax assets, net	37	28
Income taxes receivable	225	69
Prepaid expenses and other	74	81
Assets held for disposition	2	38
Total Current Assets	1,465	1,267
INVESTMENTS AND OTHER ASSETS		
Goodwill	1,407	1,407
Regulatory assets	2,316	2,614
Income taxes receivable	64	217
Restricted cash equivalents	14	17
Assets and accrued interest related to uncertain tax positions	9	18
Derivative assets	4	8
Other	158	163
Assets held for disposition	—	1,237
Total Investments and Other Assets	3,972	5,681
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	14,277	13,625
Accumulated depreciation	(4,802)	(4,779)
Net Property, Plant and Equipment	9,475	8,846
TOTAL ASSETS	$ 14,912	$ 15,794

The accompanying Notes are an integral part of these Consolidated Financial Statements.

PEPCO HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2013	December 31, 2012
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 404	$ 965
Current portion of long-term debt and project funding	695	569
Accounts payable and accrued liabilities	492	553
Capital lease obligations due within one year	9	8
Taxes accrued	50	75
Interest accrued	83	47
Liabilities and accrued interest related to uncertain tax positions	378	9
Derivative liabilities	—	4
Other	263	272
Liabilities associated with assets held for disposition	4	41
Total Current Liabilities	2,378	2,543
DEFERRED CREDITS		
Regulatory liabilities	461	501
Deferred income tax liabilities, net	2,847	3,208
Investment tax credits	18	20
Pension benefit obligation	310	449
Other postretirement benefit obligations	255	454
Liabilities and accrued interest related to uncertain tax positions	29	15
Derivative liabilities	14	11
Other	192	191
Liabilities associated with assets held for disposition	—	2
Total Deferred Credits	4,126	4,851
LONG-TERM LIABILITIES		
Long-term debt	3,805	3,648
Transition bonds issued by ACE Funding	226	256
Long-term project funding	10	12
Capital lease obligations	65	70
Total Long-Term Liabilities	4,106	3,986
COMMITMENTS AND CONTINGENCIES (NOTE 14)		
EQUITY		
Common stock, $.01 par value, 400,000,000 shares authorized, 249,713,980 and 230,015,427 shares outstanding, respectively	2	2
Premium on stock and other capital contributions	3,734	3,383
Accumulated other comprehensive loss	(40)	(48)
Retained earnings	606	1,077
Total Equity	4,302	4,414
TOTAL LIABILITIES AND EQUITY	$ 14,912	$ 15,794

The accompanying Notes are an integral part of these Consolidated Financial Statements.

PEPCO HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
	(millions of dollars)	
OPERATING ACTIVITIES		
Net (loss) income	$ (270)	$ 242
Loss (income) from discontinued operations	322	(58)
Adjustments to reconcile net (loss) income to net cash from operating activities:		
Depreciation and amortization	352	343
Deferred income taxes	(386)	279
Impairment losses	—	5
Other	(9)	(11)
Changes in:		
Accounts receivable	(55)	(90)
Inventories	(15)	(33)
Prepaid expenses	6	(31)
Regulatory assets and liabilities, net	(74)	(104)
Accounts payable and accrued liabilities	(41)	45
Pension contributions	(120)	(200)
Pension benefit obligation, excluding contributions	49	49
Cash collateral related to derivative activities	28	76
Income tax-related prepayments, receivables and payables	618	(133)
Advanced payment made to taxing authority	(242)	—
Interest accrued	37	38
Other assets and liabilities	27	23
Net current assets held for disposition	40	(21)
Net Cash From Operating Activities	267	419
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(943)	(888)
Department of Energy capital reimbursement awards received	17	25
Changes in restricted cash equivalents	(2)	(2)
Net other investing activities	—	1
Proceeds from disposal of assets held for disposition	873	202
Net Cash Used By Investing Activities	(55)	(662)
FINANCING ACTIVITIES		
Dividends paid on common stock	(201)	(185)
Common stock issued for the Dividend Reinvestment Plan and employee-related compensation	38	40
Issuances of common stock	324	—
Issuances of long-term debt	350	450
Reacquisitions of long-term debt	(96)	(165)
Repayments of short-term debt, net	(361)	(84)
Issuances of term loans	250	200
Repayments of term loans	(450)	—
Cost of issuances	(17)	(8)
Net other financing activities	(16)	—
Net Cash (Used By) From Financing Activities	(179)	248
Net Increase in Cash and Cash Equivalents	33	5
Cash and Cash Equivalents at Beginning of Period	25	109
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 58	$ 114
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash paid (received) for income taxes, net	$ 228	$ (2)
Non-cash activities:		
Reclassification of property, plant and equipment to regulatory assets	—	90
Reclassification of asset removal costs regulatory liability to accumulated depreciation	—	61

The accompanying Notes are an integral part of these Consolidated Financial Statements.

PEPCO HOLDINGS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF EQUITY
(Unaudited)

(millions of dollars, except shares)	Common Stock Shares	Common Stock Par Value	Premium on Stock	Accumulated Other Comprehensive (Loss) Income	Retained Earnings	Total
BALANCE, DECEMBER 31, 2012	230,015,427	$ 2	$ 3,383	$ (48)	$ 1,077	$4,414
Net loss	—	—	—	—	(430)	(430)
Other comprehensive income	—	—	—	6	—	6
Dividends on common stock ($0.27 per share)	—	—	—	—	(67)	(67)
Issuance of common stock:						
Original issue shares, net	18,268,100	—	321	—	—	321
Shareholder DRP original shares	370,787	—	8	—	—	8
Net activity related to stock-based awards	(102,933)	—	(6)	—	—	(6)
BALANCE, MARCH 31, 2013	248,551,381	2	3,706	(42)	580	4,246
Net income	—	—	—	—	42	42
Other comprehensive income	—	—	—	1	—	1
Dividends on common stock ($0.27 per share)	—	—	—	—	(67)	(67)
Issuance of common stock:						
Original issue shares, net	91,424	—	2	—	—	2
Shareholder DRP original shares	364,312	—	7	—	—	7
Net activity related to stock-based awards	102,933	—	5	—	—	5
BALANCE, JUNE 30, 2013	249,110,050	2	3,720	(41)	555	4,236
Net income	—	—	—	—	118	118
Other comprehensive income	—	—	—	1	—	1
Dividends on common stock ($0.27 per share)	—	—	—	—	(67)	(67)
Issuance of common stock:						
Original issue shares, net	189,408	—	3	—	—	3
Shareholder DRP original shares	414,522	—	8	—	—	8
Net activity related to stock-based awards	—	—	3	—	—	3
BALANCE, SEPTEMBER 30, 2013	249,713,980	$ 2	$ 3,734	$ (40)	$ 606	$4,302

The accompanying Notes are an integral part of these Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PEPCO HOLDINGS, INC.

(1) ORGANIZATION

Pepco Holdings, Inc. (PHI or Pepco Holdings), a Delaware corporation incorporated in 2001, is a holding company that, through the following regulated public utility subsidiaries, is engaged primarily in the transmission, distribution and default supply of electricity and the distribution and supply of natural gas (Power Delivery):

- Potomac Electric Power Company (Pepco), which was incorporated in Washington, D.C. in 1896 and became a domestic Virginia corporation in 1949,
- Delmarva Power & Light Company (DPL), which was incorporated in Delaware in 1909 and became a domestic Virginia corporation in 1979, and
- Atlantic City Electric Company (ACE), which was incorporated in New Jersey in 1924.

Each of PHI, Pepco, DPL and ACE is also a reporting company under the Securities Exchange Act of 1934, as amended. Together, Pepco, DPL and ACE constitute the Power Delivery segment, for financial reporting purposes.

Through Pepco Energy Services, Inc. and its subsidiaries (collectively, Pepco Energy Services), PHI provides energy savings performance contracting services, high voltage underground transmission cabling, and low voltage electric construction and maintenance services, and designs, constructs and operates combined heat and power and central energy plants. Pepco Energy Services constitutes a separate segment for financial reporting purposes.

PHI Service Company, a subsidiary service company of PHI, provides a variety of support services, including legal, accounting, treasury, tax, purchasing and information technology services to PHI and its operating subsidiaries. These services are provided pursuant to a service agreement among PHI, PHI Service Company and the participating operating subsidiaries. The expenses of PHI Service Company are charged to PHI and the participating operating subsidiaries in accordance with cost allocation methodologies set forth in the service agreement.

Power Delivery

Each of Pepco, DPL and ACE is a regulated public utility in the jurisdictions that comprise its service territory. Each utility owns and operates a network of wires, substations and other equipment that is classified as transmission facilities, distribution facilities or common facilities (which are used for both transmission and distribution). Transmission facilities are high-voltage systems that carry wholesale electricity into, or across, the utility’s service territory. Distribution facilities are low-voltage systems that carry electricity to end-use customers in the utility’s service territory.

Each utility is responsible for the distribution of electricity, and in the case of DPL, electricity and natural gas, in its service territory, for which it is paid tariff rates established by the applicable local public service commissions. Each utility also supplies electricity at regulated rates to retail customers in its service territory who do not elect to purchase electricity from a competitive energy supplier. The regulatory term for this supply service is Standard Offer Service in Delaware, the District of Columbia and Maryland, and Basic Generation Service in New Jersey. In the notes to the consolidated financial statements, these supply service obligations are referred to generally as Default Electricity Supply.

Pepco Energy Services

Pepco Energy Services is engaged in the following businesses:

- providing energy savings performance contracting services principally to federal, state and local government customers, and designing, constructing and operating combined heat and power and central energy plants, and
- providing high voltage underground transmission construction and maintenance services to customers throughout the United States, as well as low voltage electric construction and maintenance services and streetlight construction services to utilities, municipalities and other customers in the Washington, D.C. metropolitan area.

During 2012, Pepco Energy Services deactivated its Buzzard Point oil-fired generation facility and its Benning Road oil-fired generation facility. Pepco Energy Services placed the facilities into an idle condition termed a "cold closure." A cold closure requires that the utility service be disconnected so that the facilities are no longer operable and that the facilities require only essential maintenance until they are completely decommissioned. During the third quarter of 2013, Pepco Energy Services determined that it would be more cost effective to pursue the demolition of the Benning Road generation facility and realization of the scrap metal salvage value of the facility instead of maintaining cold closure status. As a result of this change in intent, Pepco Energy Services reduced its asset retirement obligation related to the facility by $2 million. The demolition of the facility is expected to commence in the first quarter of 2014 and Pepco Energy Services will recognize the salvage proceeds associated with the scrap metals at the facility as realized.

Discontinued Operations

Cross-Border Energy Lease Investments

Through its subsidiary Potomac Capital Investment Corporation (PCI), PHI maintained a portfolio of cross-border energy lease investments. During the third quarter of 2013, PHI completed the termination of its interests in its cross-border energy lease investments. As a result, beginning with PHI's consolidated financial statements for the three and nine months ended September 30, 2013, the cross-border energy lease investments, which comprised substantially all of the operations of the Other Non-Regulated segment, are being accounted for as discontinued operations. The remaining operations of the Other Non-Regulated segment, which no longer meet the definition of a separate segment for financial reporting purposes, are being included in Corporate and Other. Substantially all of the information in these notes to the consolidated financial statements with respect to the cross-border energy lease investments has been consolidated in Note (16), "Discontinued Operations – Cross-Border Energy Lease Investments."

Pepco Energy Services

In December 2009, PHI announced the wind-down of the retail energy supply component of the Pepco Energy Services business, which was comprised of the retail electric and retail natural gas supply businesses. Pepco Energy Services implemented the wind-down by not entering into any new retail electric or natural gas supply contracts while continuing to perform under its existing retail electric and natural gas supply contracts through their respective expiration dates. On March 21, 2013, Pepco Energy Services entered into an agreement whereby a third party assumed all the rights and obligations of the remaining retail natural gas supply customer contracts, and the associated supply obligations, inventory and derivative contracts. The transaction was completed on April 1, 2013. In addition, Pepco Energy Services completed the wind-down of its retail electric supply business in the second quarter of 2013 by terminating its remaining customer supply and wholesale purchase obligations beyond June 30, 2013. The operations of Pepco Energy Services' retail electric and retail natural gas supply businesses are being accounted for as discontinued operations and are no longer a part of the Pepco Energy Services segment for financial reporting purposes. Substantially all of the information in these notes to the consolidated financial statements with respect to Pepco Energy Services' retail energy supply business has been consolidated in Note (16), "Discontinued Operations – Retail Electric and Natural Gas Supply Businesses of Pepco Energy Services."

(2) SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation

Pepco Holdings' unaudited consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). Pursuant to the rules and regulations of the Securities and Exchange Commission, certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted. Therefore, these consolidated financial statements should be read along with the annual consolidated financial statements included in PHI's annual report on Form 10-K for the year ended December 31, 2012, as revised in PHI's Form 8-K dated August 30, 2013. In the opinion of PHI's management, the unaudited consolidated financial statements contain all adjustments (which all are of a normal recurring nature) necessary to state fairly Pepco Holdings' financial condition as of September 30, 2013, in accordance with GAAP. The year-end December 31, 2012 consolidated balance sheet included herein was derived from audited consolidated financial statements, but does not include all disclosures required by GAAP. Interim results for the three and nine months ended September 30, 2013 may not be indicative of PHI's results that will be realized for the full year ending December 31, 2013.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities in the consolidated financial statements and accompanying notes. Although Pepco Holdings believes that its estimates and assumptions are reasonable, they are based upon information available to management at the time the estimates are made. Actual results may differ significantly from these estimates.

Significant matters that involve the use of estimates include the assessment of contingencies, future cash flows and fair value amounts for use in asset and goodwill impairment calculations, fair value calculations for derivative instruments, pension and other postretirement benefit assumptions, the assessment of the probability of recovery of regulatory assets, accrual of storm restoration costs, accrual of unbilled revenue, recognition of changes in network service transmission rates for prior service year costs, accrual of self-insurance reserves for general and auto liability claims, accrual of interest related to income taxes, the recognition of income tax benefits for investments in finance leases held in trust associated with PHI's portfolio of cross-border energy lease investments (see Note (16), "Discontinued Operations – Cross-Border Energy Lease Investments"), and income tax provisions and reserves. Additionally, PHI is subject to legal, regulatory and other proceedings and claims that arise in the ordinary course of its business. PHI records an estimated liability for these proceedings and claims when it is probable that a loss has been incurred and the loss is reasonably estimable.

Consolidation of Variable Interest Entities

PHI assesses its contractual arrangements with variable interest entities to determine whether it is the primary beneficiary and thereby has to consolidate the entities in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 810. The guidance addresses conditions under which an entity should be consolidated based upon variable interests rather than voting interests. Subsidiaries of PHI have the following contractual arrangements to which the guidance applies.

ACE Power Purchase Agreements

PHI, through its ACE subsidiary, is a party to three power purchase agreements (PPAs) with unaffiliated, non-utility generators (NUGs) totaling 459 megawatts (MWs). One of the agreements ends in 2016 and the other two end in 2024. Since 2004, PHI has been unable to obtain sufficient information to determine whether these three entities were variable interest entities or if ACE was the primary beneficiary. As a result, PHI applied the scope exemption from the consolidation guidance for enterprises that have not been able to obtain such information.

Purchase activities with the NUGs, including excess power purchases not covered by the PPA, for the three months ended September 30, 2013 and 2012 were approximately $61 million and $56 million, respectively, of which approximately $54 million and $53 million, respectively, consisted of power purchases under the PPAs. Purchase activities with the NUGs for the nine months ended September 30, 2013 and 2012 were approximately $168 million and $156 million, respectively, of which approximately $157 million and $151 million, respectively, consisted of power purchases under the PPAs. The power purchase costs are recoverable from ACE's customers through regulated rates.

DPL Renewable Energy Transactions

DPL is subject to Renewable Energy Portfolio Standards (RPS) in the state of Delaware that require it to obtain renewable energy credits (RECs) for energy delivered to its customers. DPL's costs associated with obtaining RECs to fulfill its RPS obligations are recoverable from its customers by law. As of September 30, 2013, PHI, through its DPL subsidiary, is a party to three land-based wind PPAs in the aggregate amount of 128 MWs and one solar PPA with a 10 MW facility. Each of the facilities associated with these PPAs is operational, and DPL is obligated to purchase energy and RECs in amounts generated and delivered by the wind facilities and solar renewable energy credits (SRECs) from the solar facility up to certain amounts (as set forth below) at rates that are primarily fixed under the respective PPA. PHI has concluded that consolidation is not required for any of these PPAs under the FASB guidance on the consolidation of variable interest entities.

DPL is obligated to purchase energy and RECs from one of the wind facilities through 2024 in amounts not to exceed 50 MWs, from the second wind facility through 2031 in amounts not to exceed 40 MWs, and from the third wind facility through 2031 in amounts not to exceed 38 MWs. DPL's purchases under the three wind PPAs totaled $4 million for each of the three months ended September 30, 2013 and 2012. DPL's purchases under the three wind PPAs totaled $21 million and $20 million for the nine months ended September 30, 2013 and 2012, respectively.

The term of the agreement with the solar facility is 20 years and DPL is obligated to purchase SRECs in an amount up to 70 percent of the energy output at a fixed price. DPL's purchases under the solar agreement were $1 million for each of the three months ended September 30, 2013 and 2012. DPL's purchases under the solar agreement were $2 million for each of the nine months ended September 30, 2013 and 2012.

On October 18, 2011, the Delaware Public Service Commission (DPSC) approved a tariff submitted by DPL in accordance with the requirements of the RPS specific to fuel cell facilities totaling 30 MWs to be constructed by a qualified fuel cell provider. The tariff and the RPS establish that DPL is an agent to collect payments in advance from its distribution customers and remit them to the qualified fuel cell provider for each MW hour (MWh) of energy produced by the fuel cell facilities over 21 years. DPL has no obligation to the qualified fuel cell provider other than to remit payments collected from its distribution customers pursuant to the tariff. The RPS provides for a reduction in DPL's REC requirements based upon the actual energy output of the facilities. At September 30, 2013 and 2012, 15 MWs and 3MWs of capacity were available from fuel cell facilities placed in service under the tariff, respectively. DPL billed $7 million and less than $1 million to distribution customers for the three months ended September 30, 2013 and 2012, respectively. DPL billed $13 million and less than $1 million to distribution customers for the nine months ended September 30, 2013 and 2012, respectively. DPL has concluded that consolidation under the variable interest entity consolidation guidance is not required for this arrangement.

Atlantic City Electric Transition Funding LLC

Atlantic City Electric Transition Funding LLC (ACE Funding) was established in 2001 by ACE solely for the purpose of securitizing authorized portions of ACE's recoverable stranded costs through the issuance and sale of bonds (Transition Bonds). The proceeds of the sale of each series of Transition Bonds have been transferred to ACE in exchange for the transfer by ACE to ACE Funding of the right to collect non-bypassable transition bond charges (the Transition Bond Charges) from ACE customers pursuant to bondable stranded costs rate orders issued by the New Jersey Board of Public Utilities (NJBPU) in an amount sufficient to fund the principal and interest payments on the Transition Bonds and related taxes, expenses and fees (Bondable Transition Property). ACE collects the Transition Bond Charges from its customers on behalf of ACE Funding and the holders of the Transition Bonds. The assets of ACE Funding, including the Bondable Transition Property, and the Transition Bond Charges collected from ACE's customers, are not available to creditors of ACE. The holders of the Transition Bonds have recourse only to the assets of ACE Funding. ACE owns 100 percent of the equity of ACE Funding and PHI consolidates ACE Funding in its consolidated financial statements as ACE is the primary beneficiary of ACE Funding under the variable interest entity consolidation guidance.

ACE Standard Offer Capacity Agreements

In April 2011, ACE entered into three Standard Offer Capacity Agreements (SOCAs) by order of the NJBPU, each with a different generation company. The SOCAs were established under a New Jersey law enacted to promote the construction of qualified electric generation facilities in New Jersey. The SOCAs are 15-year, financially settled transactions approved by the NJBPU that allow generation companies to receive payments from, or require them to make payments to, ACE based on the difference between the fixed price in the SOCAs and the price for capacity that clears PJM Interconnection, LLC (PJM). Each of the other electric distribution companies (EDCs) in New Jersey has entered into SOCAs having the same terms with the same generation companies. ACE's share of the payments received from or the payments made to the generation companies is currently estimated to be approximately 15 percent, based on its proportionate share of the total New Jersey electric load for all EDCs. The NJBPU has ordered that ACE is obligated to distribute to its distribution customers all payments it receives from the generation companies and may recover from its distribution customers all payments it makes to the generation companies.

In May 2013, all three generation companies under the SOCAs bid into the PJM 2016-2017 capacity auction. Two of the generators cleared the capacity auction, while the third did not. For each SOCA that clears the capacity auction, ACE records a derivative asset (liability) for the estimated fair value of that SOCA and records an offsetting regulatory liability (asset) as described in more detail in Note (12), "Derivative Instruments and Hedging Activities," and Note (13), "Fair Value Disclosures." Effective July 1, 2013, the SOCA with the third generation company was terminated as the generation company did not clear a PJM capacity auction by the commencement date required under the SOCA. PHI has concluded that consolidation of the generation companies is not required.

For additional discussion regarding litigation associated with the SOCAs, see Note (7), "Regulatory Matters."

Goodwill

Goodwill represents the excess of the purchase price of an acquisition over the fair value of the net assets acquired at the acquisition date. Substantially all of Pepco Holdings' goodwill was generated by Pepco's acquisition of Conectiv (now Conectiv, LLC (Conectiv)) in 2002 and is allocated entirely to Power Delivery for purposes of impairment testing based on the aggregation of its components because its utilities have similar characteristics. Pepco Holdings tests its goodwill for impairment annually as of November 1 and whenever an event occurs or circumstances change in the interim that would more likely than not reduce the fair value of a reporting unit below the carrying amount of its net assets. Factors that may result in an interim impairment test include, but are not limited to: a change in the identified reporting units; an adverse change in business conditions; a protracted decline in PHI's stock price causing market capitalization to fall below book value; an adverse regulatory action; or an impairment of long-lived assets in the reporting unit. PHI concluded that an interim impairment test was not required during the nine months ended September 30, 2013.

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in Pepco Holdings' gross revenues were $98 million and $103 million for the three months ended September 30, 2013 and 2012, respectively. Taxes included in Pepco Holdings' gross revenues were $264 million and $275 million for the nine months ended September 30, 2013 and 2012, respectively.

Reclassifications and Adjustments

Certain prior period amounts have been reclassified in order to conform to the current period presentation. The following adjustment has been recorded and is not considered material either individually or in the aggregate:

DPL Operating Revenue Adjustment

In the second quarter of 2012, DPL recorded an adjustment to correct an overstatement of unbilled revenue in its natural gas distribution business related to prior periods. The adjustment resulted in a decrease in Operating Revenue of $1 million for the nine months ended September 30, 2012.

Revision to Prior Period Financial Statements

PCI Deferred Income Tax Liability Adjustment

Since 1999, PCI had not recorded a deferred tax liability related to a temporary difference between the financial reporting basis and the tax basis of an investment in a wholly owned partnership. In the second quarter of 2013, PHI re-evaluated this accounting treatment and found it to be in error, requiring an adjustment related to prior periods. PHI determined that the cumulative adjustment required for the periods prior to 2008 (2008 representing the earliest year for which selected consolidated financial data were presented in Part II, Item 6. "Selected Financial Data" included in PHI's annual report on Form 10-K for the year ended December 31, 2012 (2012 Form 10-K)) was a charge to earnings of $32 million. The adjustment was not considered to be material, individually or in the aggregate, to previously issued financial statements; however, the cumulative impact would have been material to PHI's reported net income for the three and six months ended June 30, 2013, as well as estimated full year 2013 results, if corrected in 2013. As a result, during the second quarter of 2013, PHI revised its prior period financial statements to correct this error, and the table below illustrates the effects of this revision on PHI's consolidated balance sheets as of March 31, 2013 and December 31, 2012, 2011, 2010 and 2009 for those line items affected (these revisions had no impact on PHI's consolidated statements of income (loss), comprehensive income (loss), and cash flows for the periods reported below).

	As Filed	Adjustment *(millions of dollars)*	As Revised
March 31, 2013			
Deferred income tax liabilities, net	$2,685	$ 32	$ 2,717
Total deferred credits	4,270	32	4,302
Retained earnings	612	(32)	580
Total equity	4,278	(32)	4,246
December 31, 2012			
Deferred income tax liabilities, net	$3,176	$ 32	$ 3,208
Total deferred credits	4,819(a)	32	4,851
Retained earnings	1,109	(32)	1,077
Total equity	4,446	(32)	4,414
December 31, 2011			
Deferred income tax liabilities, net	$2,863	$ 32	$ 2,895
Total deferred credits	4,533	32	4,565
Retained earnings	1,072	(32)	1,040
Total equity	4,336	(32)	4,304
December 31, 2010			
Retained earnings	$1,059	$ (32)	$ 1,027
December 31, 2009			
Retained earnings	$1,268	$ (32)	$ 1,236

(a) The amount of total deferred credits differs from the amount reported in PHI's 2012 Form 10-K due to certain reclassifications.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Balance Sheet (ASC 210)

In December 2011, the FASB issued new disclosure requirements for financial assets and financial liabilities, such as derivatives, that are subject to contractual netting arrangements. The new disclosure requirements include information about the gross exposure of the instruments and the net exposure of the instruments under contractual netting arrangements, how the exposures are presented in the financial statements, and the terms and conditions of the contractual netting arrangements. PHI adopted the new guidance during the first quarter of 2013 and concluded it did not have a material impact on its consolidated financial statements.

Comprehensive Income (ASC 220)

The new disclosure requirements for reclassifications from accumulated other comprehensive income were effective for PHI beginning with its March 31, 2013 consolidated financial statements and required PHI to present additional information about its reclassifications from accumulated other comprehensive income in a single footnote or on the face of its consolidated financial statements. The additional information required to be disclosed includes a presentation of the components of accumulated other comprehensive income that have been reclassified by source (e.g., commodity derivatives), and the income statement line item (e.g., Fuel and Purchased Energy) affected by the reclassification. PHI has provided the new required disclosures in Note (15), "Accumulated Other Comprehensive Loss."

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Joint and Several Liability Arrangements (ASC 405)

In February 2013, the FASB issued new recognition and disclosure requirements for certain joint and several liability arrangements where the total amount of the obligation is fixed at the reporting date. For arrangements within the scope of this standard, PHI will be required to include in its liabilities the additional amounts it expects to pay on behalf of its co-obligors, if any. PHI will also be required to provide additional disclosures including the nature of the arrangements with its co-obligors, the total amounts outstanding under the arrangements between PHI and its co-obligors, the carrying value of the liability, and the nature and limitations of any recourse provisions that would enable recovery from other entities.

The new requirements would be effective retroactively beginning on January 1, 2014, with implementation required for prior periods if joint and several liability arrangement obligations exist as of January 1, 2014. PHI is evaluating the impact of this new guidance on its consolidated financial statements.

Income Taxes (ASC 740)

In July 2013, the FASB issued new guidance that will require the netting of certain unrecognized tax benefits against a deferred tax asset for a loss or other similar tax carryforward that would apply upon settlement of the uncertain tax position. The new requirements are effective prospectively beginning with PHI's March 31, 2014 consolidated financial statements for all unrecognized tax benefits existing at the adoption date. Retrospective implementation and early adoption of the guidance are permitted. PHI is evaluating the impact of this new guidance on its consolidated financial statements.

(5) SEGMENT INFORMATION

Pepco Holdings' management has identified its operating segments at September 30, 2013 as Power Delivery and Pepco Energy Services. In the tables below, the Corporate and Other column is included to reconcile the segment data with consolidated data and includes unallocated Pepco Holdings' (parent company) capital costs, such as financing costs. Segment financial information for continuing operations for the three and nine months ended September 30, 2013 and 2012 is as follows:

	Three Months Ended September 30, 2013 (millions of dollars)			
	Power Delivery	Pepco Energy Services	Corporate and Other (a)	PHI Consolidated
Operating Revenue	$ 1,298	$ 48	$ (2)	$ 1,344
Operating Expenses (b)	1,067	50	(8)	1,109
Operating Income (Loss)	231	(2)	6	235
Interest Expense	58	1	9	68
Other Income (Loss)	8	1	(1)	8
Income Tax Expense (Benefit)	67	(1)	(1)	65
Net Income (Loss) from Continuing Operations	114	(1)	(3)	110
Total Assets (excluding Assets Held for Disposition)	12,790	341	1,779	14,910
Construction Expenditures	$ 293	$ 1	$ 33	$ 327

(a) Total Assets in this column includes Pepco Holdings' goodwill balance of $1.4 billion, all of which is allocated to Power Delivery for purposes of assessing impairment. Total assets also include capital expenditures related to certain hardware and software expenditures which primarily benefit Power Delivery. These expenditures are recorded as incurred in Corporate and Other and are allocated to Power Delivery once the assets are placed in service. Corporate and Other includes intercompany amounts of $(2) million for Operating Revenue, $(1) million for Operating Expenses, $(2) million for Interest Income and $(2) million for Interest Expense.

(b) Includes depreciation and amortization expense of $124 million, consisting of $116 million for Power Delivery and $8 million for Corporate and Other.

	Three Months Ended September 30, 2012 (millions of dollars)			
	Power Delivery	Pepco Energy Services	Corporate and Other (a)	PHI Consolidated
Operating Revenue	$ 1,335	$ 57	$ (3)	$ 1,389
Operating Expenses (b)	1,136	64(c)	(12)	1,188
Operating Income (Loss)	199	(7)	9	201
Interest Income	—	1	(1)	—
Interest Expense	56	1	9	66
Other Income	8	1	—	9
Income Tax Expense (Benefit)	59	(3)	1	57
Net Income (Loss) from Continuing Operations	92	(3)	(2)	87
Total Assets (excluding Assets Held for Disposition)	12,039	426	1,915	14,380
Construction Expenditures	$ 289	$ 1	$ 9	$ 299

(a) Total Assets in this column includes Pepco Holdings' goodwill balance of $1.4 billion, all of which is allocated to Power Delivery for purposes of assessing impairment. Total assets also include capital expenditures related to certain hardware and software expenditures which primarily benefit Power Delivery. These expenditures are recorded as incurred in Corporate and Other and are allocated to Power Delivery once the assets are placed in service. Corporate and Other includes intercompany amounts of $(3) million for Operating Revenue, $(4) million for Operating Expenses, $(7) million for Interest Income and $(5) million for Interest Expense.

(b) Includes depreciation and amortization expense of $122 million, consisting of $114 million for Power Delivery, $2 million for Pepco Energy Services and $6 million for Corporate and Other.

(c) Includes impairment losses of $2 million pre-tax ($1 million after-tax) at Pepco Energy Services associated with the combustion turbines at Buzzard Point.

	Nine Months Ended September 30, 2013 (millions of dollars)			
	Power Delivery	Pepco Energy Services	Corporate and Other (a)	PHI Consolidated
Operating Revenue	$ 3,428	$ 154	$ (7)	$ 3,575
Operating Expenses (b)	2,934	151	(23)	3,062
Operating Income	494	3	16	513
Interest Expense	172	1	32	205
Other Income	21	2	1	24
Income Tax Expense (c)	115	1	164(d)	280
Net Income (Loss) from Continuing Operations	228	3	(179)	52
Total Assets (excluding Assets Held for Disposition)	12,790	341	1,779	14,910
Construction Expenditures	$ 856	$ 2	$ 85	$ 943

(a) Total Assets in this column includes Pepco Holdings' goodwill balance of $1.4 billion, all of which is allocated to Power Delivery for purposes of assessing impairment. Total assets also include capital expenditures related to certain hardware and software expenditures which primarily benefit Power Delivery. These expenditures are recorded as incurred in Corporate and Other and are allocated to Power Delivery once the assets are placed in service. Corporate and Other includes intercompany amounts of $(8) million for Operating Revenue, $(7) million for Operating Expenses, $(7) million for Interest Income and $(6) million for Interest Expense.

(b) Includes depreciation and amortization expense of $352 million, consisting of $327 million for Power Delivery, $4 million for Pepco Energy Services and $21 million for Corporate and Other.

(c) Includes after-tax interest associated with uncertain and effectively settled tax positions allocated to each member of the consolidated group, including a $12 million interest benefit for Power Delivery and interest expense of $66 million for Corporate and Other.

(d) Includes non-cash charges of $101 million representing the establishment of valuation allowances against certain deferred tax assets of PCI included in Corporate and Other.

	Nine Months Ended September 30, 2012 (millions of dollars)			
	Power Delivery	Pepco Energy Services	Corporate and Other (a)	PHI Consolidated
Operating Revenue	$ 3,374	$ 205	$ (10)	$ 3,569
Operating Expenses (b)	2,950	209(c)	(29)	3,130
Operating Income (Loss)	424	(4)	19	439
Interest Income	—	1	(1)	—
Interest Expense	162	2	26	190
Other Income	24	1	2	27
Income Tax Expense (Benefit)	93	(2)	1	92
Net Income (Loss) from Continuing Operations	193	(2)	(7)	184
Total Assets (excluding Assets Held for Disposition)	12,039	426	1,915	14,380
Construction Expenditures	$ 854	$ 11	$ 23	$ 888

(a) Total Assets in this column includes Pepco Holdings' goodwill balance of $1.4 billion, all of which is allocated to Power Delivery for purposes of assessing impairment. Total assets also include capital expenditures related to certain hardware and software expenditures which primarily benefit Power Delivery. These expenditures are recorded as incurred in Corporate and Other and are allocated to Power Delivery once the assets are placed in service. Corporate and Other includes intercompany amounts of $(11) million for Operating Revenue, $(11) million for Operating Expenses, $(18) million for Interest Income and $(15) million for Interest Expense.

(b) Includes depreciation and amortization expense of $343 million, consisting of $313 million for Power Delivery, $12 million for Pepco Energy Services and $18 million for Corporate and Other.

(c) Includes impairment losses of $5 million pre-tax ($3 million after-tax) at Pepco Energy Services associated primarily with an investment in a landfill gas-fired electric generation facility and the combustion turbines at Buzzard Point.

(6) GOODWILL

PHI's goodwill balance of $1.4 billion was unchanged during the nine months ended September 30, 2013. Substantially all of PHI's goodwill balance was generated by Pepco's acquisition of Conectiv in 2002 and is allocated entirely to the Power Delivery reporting unit based on the aggregation of its regulated public utility company components for purposes of assessing impairment under FASB guidance on goodwill and other intangibles (ASC 350).

PHI's annual impairment test as of November 1, 2012 indicated that goodwill was not impaired. For the nine months ended September 30, 2013, PHI concluded that there were no events requiring it to perform an interim goodwill impairment test. PHI will perform its next annual impairment test as of November 1, 2013.

(7) REGULATORY MATTERS

Rate Proceedings

Over the last several years, PHI's utility subsidiaries have proposed in each of their respective jurisdictions the adoption of a mechanism to decouple retail distribution revenue from the amount of power delivered to retail customers. To date:

- A bill stabilization adjustment (BSA) was approved and implemented for Pepco and DPL electric service in Maryland and for Pepco electric service in the District of Columbia.
- A modified fixed variable rate design (MFVRD) for DPL electric and natural gas service in Delaware is under consideration by the DPSC.
- In New Jersey, a BSA proposed by ACE in 2009 was not approved and there is no BSA proposal currently pending.

Under the BSA, customer distribution rates are subject to adjustment (through a credit or surcharge mechanism), depending on whether actual distribution revenue per customer exceeds or falls short of the revenue-per-customer amount approved by the applicable public service commission. The MFVRD under consideration by the DPSC in Delaware provides for a fixed customer charge (i.e., not tied to the customer's volumetric consumption of electricity or natural gas) to recover the utility's fixed costs, plus a reasonable rate of return. Although different from the BSA, PHI views the MFVRD as an appropriate distribution revenue decoupling mechanism.

The following table shows, for each of PHI's utility subsidiaries, the base rate cases currently pending. Additional information concerning each of these filings is provided in the discussion below.

Jurisdiction/Company	Requested Revenue Requirement Increase *(millions of dollars)*	Requested Return on Equity	Filing Date	Expected Timing of Decision
DC – Pepco	$ 44.1(a)	10.25%	March 8, 2013	Q1-2014
DE – DPL (Electric)	$ 39.0(b)	10.25%	March 22, 2013	Q1-2014

(a) Reflects DPL's updated revenue requirement as filed on July 15, 2013.
(b) Reflects DPL's updated revenue requirement as filed on September 20, 2013.

The following table shows, for each of PHI's utility subsidiaries, the base rate cases completed in 2013. Additional information concerning each of these cases is provided in the discussion below.

Jurisdiction/Company	Approved Revenue Requirement Increase *(millions of dollars)*	Approved Return on Equity	Completion Date	Rate Effective Date
NJ – ACE	$25.5	9.75%	June 21, 2013	July 1, 2013
MD – Pepco	27.9	9.36%	July 12, 2013	July 12, 2013
MD – DPL	15.0	9.81%	August 30, 2013	September 15, 2013
DE – DPL (Gas)	$6.8	9.75%	October 22, 2013	November 1, 2013

Delaware

Gas Cost Rates

DPL makes an annual Gas Cost Rate (GCR) filing with the DPSC for the purpose of allowing DPL to recover natural gas procurement costs through customer rates. On August 28, 2013, DPL made its 2013 GCR filing. The rates proposed in the 2013 GCR filing would result in a GCR decrease of approximately 5.5%. On September 26, 2013, the DPSC issued an order authorizing DPL to place the new rates into effect on November 1, 2013, subject to refund and pending final DPSC approval.

Electric Distribution Base Rates

On March 22, 2013, DPL submitted an application with the DPSC to increase its electric distribution base rates. The filing seeks approval of an annual rate increase of approximately $39 million (as adjusted by DPL on September 20, 2013), based on a requested ROE of 10.25%. The requested rate increase seeks to recover expenses associated with DPL's ongoing efforts to maintain safe and reliable service. The DPSC suspended the full proposed increase and, as permitted by state law, DPL implemented an interim increase of $2.5 million on June 1, 2013, subject to refund and pending final DPSC approval. On October 8, 2013, the DPSC approved DPL's request to implement an additional interim increase of $25.1 million, effective on October 22, 2013, bringing the total interim rates in effect subject to refund to $27.6 million. A final DPSC decision is expected by the first quarter of 2014.

Forward Looking Rate Plan

On October 2, 2013, DPL filed a multi-year rate plan, referred to as the Forward Looking Rate Plan (FLRP). As proposed, the FLRP would establish electric distribution base rates to be increased annually over a four-year period, resulting in four annual DPL electric distribution rate increases, and the amount of the increase over that period would be approximately $56 million. While the proposed authorized ROE under the FLRP is 9.75%, the FLRP as proposed provides the opportunity to achieve estimated earned ROEs of 7.41% and 8.8% in years one and two, respectively, and 9.75% in both years three and four of the plan.

In addition, DPL proposes that as part of the FLRP, in order to provide a higher minimum required standard of reliability for DPL's customers, the reliability standards by which DPL's reliability is measured would be made more stringent in each year of the FLRP. In addition, DPL has offered to refund an annual aggregate of $500,000 to customers in each year of the FLRP that it fails to meet the proposed stricter minimum reliability standards.

On October 22, 2013, the DPSC opened a docket for the purpose of reviewing the details of the FLRP, but stated that the electric distribution base rate case discussed above should be concluded before the FLRP is addressed. DPL expects that the FLRP will be updated and re-filed at the conclusion of the electric distribution base rate case. A schedule for the FLRP docket has not yet been established.

Gas Distribution Base Rates

On December 7, 2012, DPL submitted an application with the DPSC to increase its natural gas distribution base rates. The filing seeks approval of an annual rate increase of approximately $12.0 million (as adjusted by DPL on July 15, 2013), based on a requested ROE of 10.25%. The requested rate increase is for the purposes of recovering expenses associated with DPL's ongoing efforts to maintain safe and reliable service and to provide enhanced customer service technology. The DPSC suspended the full proposed increase and, as permitted by state law, DPL implemented an interim increase of $2.5 million on February 5, 2013, subject to refund and pending final DPSC approval. On July 2, 2013, the DPSC approved DPL's request to implement an additional interim increase of $8 million, effective on July 7, 2013. On October 22, 2013, the DPSC approved a settlement entered into on August 27, 2013 by the DPSC Staff, the Delaware Division of the Public Advocate and DPL, which provides for an annual rate increase of $6.8 million. The excess amount collected when the interim increases were in effect will be returned to customers. While the approved settlement provides that no understanding was reached concerning the appropriate ROE, for reporting purposes and for calculating the AFUDC, construction work in progress (CWIP), regulatory asset carrying costs and other accounting metrics, the rate of 9.75% should be used. The new rates became effective on November 1, 2013.

The approved settlement also provides for a phase-in of the recovery of the deferred costs associated with DPL's deployment of the interface management unit (IMU), which allows for the remote reading of the gas meter portion of its advanced metering infrastructure (AMI), through base rates over a two-year period, assuming specific milestones are met and pursuant to the following schedule: 50% of the IMU portion of DPL's AMI will be put into rates on May 1, 2014, and the remainder will be put into rates on March 1, 2015. DPL also agreed that its next natural gas distribution base rate application may be filed with the DPSC no earlier than January 1, 2015.

<u>*District of Columbia*</u>

On March 8, 2013, Pepco filed an application with the District of Columbia Public Service Commission (DCPSC) to increase its annual electric distribution base rates by approximately $44.1 million (as adjusted by Pepco on September 16, 2013), based on a requested ROE of 10.25%. The requested rate increase is for the purpose of recovering (i) Pepco's expenses associated with ongoing efforts to maintain safe and reliable service for its customers, (ii) Pepco's investment in infrastructure to maintain and harden the electric distribution system, and (iii) Pepco's investment in major reliability enhancement improvements. Evidentiary hearings are expected to begin on November 4, 2013 and a final DCPSC decision is expected in the first quarter of 2014.

Maryland

DPL Electric Distribution Base Rates

On March 29, 2013, DPL submitted an application with the Maryland Public Service Commission (MPSC) to increase its electric distribution base rates by approximately $22.8 million, based on a requested ROE of 10.25%. The requested rate increase was for the purpose of recovering reliability enhancements to serve Maryland customers. DPL also proposed a three-year Grid Resiliency Charge rider for recovery of costs totaling approximately $10.2 million associated with its plan to accelerate investments in electric distribution infrastructure in a condensed timeframe. Acceleration of resiliency improvements was one of several recommendations included in a September 2012 report from Maryland's Grid Resiliency Task Force (as discussed below under "Resiliency Task Forces"). Specific projects under DPL's Grid Resiliency Charge plan included accelerating its tree-trimming cycle and upgrading five additional feeders per year for two years. In addition, DPL proposed a reliability performance-based mechanism that would allow DPL to earn up to $500,000 as an incentive for meeting enhanced reliability goals in 2015, but provided for a credit to customers of up to $500,000 in total if DPL does not meet at least the minimum reliability performance targets. DPL requested that any credits or charges would flow through the proposed Grid Resiliency Charge rider.

On August 30, 2013, the MPSC issued a final order approving a settlement among DPL, the MPSC staff and the Maryland Office of People's Counsel (OPC). The approved settlement provides for an annual rate increase of approximately $15 million. While the settlement does not specify an overall ROE, the parties did agree that the ROE for purposes of calculating the AFUDC and regulatory asset carrying costs would be 9.81%. The approved settlement also provides for (i) recovery of storm restoration costs incurred as a result of recent major storm events, including the derecho storm in June 2012 and Hurricane Sandy in October 2012, by amortizing the related deferred operation and maintenance expenses of approximately $6 million over a five-year period with the unamortized balance included in rate base, and (ii) a Grid Resiliency Charge for recovery of costs totaling approximately $4.2 million associated with DPL's proposed plan to accelerate investments related to certain priority feeders, provided that DPL provides additional information to the MPSC before implementing the surcharge related to performance objectives, milestones and costs, and makes annual filings with the MPSC thereafter concerning this project, which will permit the MPSC to establish the applicable Grid Resiliency Charge rider for the following year. The approved settlement does not provide for approval of a portion of the Grid Resiliency Charge related to the proposed acceleration of the tree-trimming cycle, or DPL's proposed reliability performance-based mechanism. The new rates became effective on September 15, 2013.

Pepco Electric Distribution Base Rates

In December 2011, Pepco submitted an application with the MPSC to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $68.4 million (subsequently reduced by Pepco to $66.2 million), based on a requested ROE of 10.75%. In July 2012, the MPSC issued an order approving an annual rate increase of approximately $18.1 million, based on an ROE of 9.31%. The order also reduced Pepco's depreciation rates, which lowered annual depreciation and amortization expenses by an estimated $27.3 million. The lower depreciation rates resulted from, among other things, the rebalancing of excess reserves for estimated future removal costs identified in a depreciation study conducted as part of the rate case filing. The identified excess reserves for estimated future removal costs, reported as regulatory liabilities, were reclassified to accumulated depreciation among various plant accounts. Among other things, the order also authorizes Pepco to recover the actual cost of AMI meters installed during the 2011 test year and states that cost recovery for AMI deployment will be allowed in future rate cases in which Pepco demonstrates that the system is cost effective. The new revenue rates and lower depreciation rates were effective on July 20, 2012. The Maryland OPC has sought rehearing on the portion of the order allowing Pepco to recover the costs of AMI meters installed during the test year; that motion remains pending.

On November 30, 2012, Pepco submitted an application with the MPSC to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $60.8 million, based on a requested ROE of 10.25%. The requested rate increase was for the purpose of recovering reliability enhancements to serve Maryland customers. Pepco also proposed a three-year Grid Resiliency Charge rider for recovery of costs totaling approximately $192 million associated with its plan to accelerate investments in infrastructure in a condensed timeframe. Acceleration of resiliency improvements was one of several recommendations included in a September 2012 report from Maryland's Grid Resiliency Task Force (as discussed below under "Resiliency Task Forces"). Specific projects under Pepco's Grid Resiliency Charge plan included acceleration of its tree-trimming cycle, upgrade of 12 additional feeders per year for two years and undergrounding of six distribution feeders. In addition, Pepco proposed a reliability performance-based mechanism that would allow Pepco to earn up to $1 million as an incentive for meeting enhanced reliability goals in 2015, but provided for a credit to customers of up to $1 million in total if Pepco does not meet at least the minimum reliability performance targets. Pepco requested that any credits/charges would flow through the proposed Grid Resiliency Charge rider.

On July 12, 2013, the MPSC issued an order related to Pepco's November 30, 2012 application approving an annual rate increase of approximately $27.9 million, based on an ROE of 9.36%. The order provides for the full recovery of storm restoration costs incurred as a result of recent major storm events, including the derecho storm in June 2012 and Hurricane Sandy in October 2012, by including the related capital costs in the rate base and amortizing the related deferred operation and maintenance expenses of $23.6 million over a five-year period. The order excludes the cost of AMI meters from Pepco's rate base until such time as Pepco demonstrates the cost effectiveness of the AMI system; as a result, costs for AMI meters incurred with respect to the 2012 test year and beyond will be treated as other incremental AMI costs incurred in conjunction with the deployment of the AMI system that are deferred and on which a return is earned, but only until such cost effectiveness has been demonstrated and such costs are included in rates. However, the MPSC's July 2012 order in Pepco's previous electric distribution base rate case, which allowed Pepco to recover the costs of meters installed during the 2011 test year for that case, remains in effect, and the Maryland OPC's motion for rehearing in that case remains pending.

The order also approved a Grid Resiliency Charge for recovery of costs totaling approximately $24.0 million associated with Pepco's proposed plan to accelerate investments related to certain priority feeders, provided that Pepco provides additional information to the MPSC before implementing the surcharge related to performance objectives, milestones and costs, and makes annual filings with the MPSC thereafter concerning this project, which will permit the MPSC to establish the applicable Grid Resiliency Charge rider for each following year. The MPSC did not approve the proposed acceleration of the tree-trimming cycle or the undergrounding of six distribution feeders. The MPSC rejected Pepco's proposed reliability performance-based mechanism. The new rates were effective on July 12, 2013.

On July 26, 2013, Pepco filed a notice of appeal of this July 12, 2013 order in the Circuit Court for the City of Baltimore. Other parties have also filed notices of appeal in that court and in the Circuit Court for Montgomery County. The other parties' appeals have been transferred to the Circuit Court for the City of Baltimore and consolidated with Pepco's appeal. Pepco intends to file another electric distribution base rate case with the MPSC in the fourth quarter of 2013. Pepco is continuing to review the impact of the order and may also consider other actions to more closely align its spending in Maryland to the revenue received while maintaining compliance with the MPSC's established standards applicable to the utility.

New Jersey

Electric Distribution Base Rates

On December 11, 2012, ACE submitted an application with the NJBPU, updated on January 4, 2013, to increase its electric distribution base rates by approximately $70.4 million (excluding sales-and-use taxes), based on a requested ROE of 10.25%. This proposed net increase was comprised of (i) a proposed increase to ACE's distribution rates of approximately $72.1 million and (ii) a net decrease to ACE's Regulatory Asset

Recovery Charge (a customer charge to recover deferred, NJBPU-approved expenses incurred as part of ACE's public service obligation) in the amount of approximately $1.7 million. The requested rate increase was primarily for the purposes of continuing to implement reliability-related investments and recovering system restoration costs associated with the derecho storm in June 2012 and Hurricane Sandy in October 2012. On June 21, 2013, the NJBPU approved a settlement of the parties (the NJ Rate Settlement) providing for an increase in ACE's distribution base rates in the amount of $25.5 million, based on an ROE of 9.75%. The base distribution revenue increase includes full recovery of the approximately $70.0 million in incremental storm restoration costs incurred as a result of recent major storm events, including the derecho storm and Hurricane Sandy, by including the related capital costs of approximately $44.2 million in rate base and amortizing the related deferred operation and maintenance expenses of approximately $25.8 million over a three-year period. Rates were effective on July 1, 2013.

In a March 20, 2013 order, the NJBPU established a generic proceeding to evaluate the prudence of major storm event restoration costs and expenses. Each New Jersey EDC was directed to file a separate proceeding for the evaluation of these costs. Those portions of ACE's 2012 electric base rate filing pertaining to the recovery of major storm event expenditures were to be evaluated in the context of the generic proceeding. On April 9, 2013, ACE filed a petition with the NJBPU to comply with the NJBPU's generic storm cost order. All other issues in ACE's base rate filing remained unchanged in the electric base rate proceeding discussed above. In its order approving the NJ Rate Settlement, the NJBPU found that (i) ACE's April 9, 2013 petition met all the requirements of the NJBPU's March 20, 2013 order, and (ii) the major storm event costs for the June 2012 derecho storm and Hurricane Sandy may be recovered in ACE's electric distribution base rate case, discussed above.

Update and Reconciliation of Certain Under-Recovered Balances

In February 2012, ACE submitted a petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE's long-term power purchase contracts with the NUGs, (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program for low income customers) and ACE's uncollected accounts and (iii) operating costs associated with ACE's residential appliance cycling program. The filing proposed to recover the projected deferred under-recovered balance related to the NUGs of $113.8 million as of May 31, 2012 through a four-year amortization schedule. In June 2012, the NJBPU approved a stipulation of settlement signed by the parties, which provided for provisional rates that went into effect on July 1, 2012. The net impact of adjusting the charges (consisting of both the annual impact of the proposed four-year amortization of the historical under-recovered NUG balances of $127.0 million as of June 30, 2012 and the going-forward cost recovery of all the other charges for the period July 1, 2012 through May 31, 2013, and including associated changes in sales-and-use taxes) is an overall annual rate increase of approximately $55.3 million. The rates were deemed "provisional" because ACE's filing had not been updated for actual revenues and expenses for May and June 2012 until the March 5, 2013 petition described below was filed. A review by the NJBPU of the final underlying costs for reasonableness and prudence will be completed. On June 11, 2013, this matter was transmitted to the New Jersey Office of Administrative Law (OAL) for hearing, which has been scheduled for December 2013.

On March 5, 2013, ACE submitted a new petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE's long-term power purchase contracts with the NUGs, (ii) costs related to surcharges for the New Jersey Societal Benefit Program and ACE's uncollected accounts and (iii) operating costs associated with ACE's residential appliance cycling program. The filing proposed to recover the forecasted above-market NUG costs of approximately $67.9 million for the period June 1, 2013 through May 31, 2014, the projected deferred under-recovered balance related to the NUGs of approximately $40.8 million as of May 31, 2013, and an additional approximately $32.9 million associated with the deferred under-recovered balance that is being amortized over a four-year amortization period. In May 2013, the NJBPU approved a stipulation of settlement signed by the parties, which provided for provisional rates that went into effect on June 1, 2013.The net impact of adjusting the charges updated for actual data through March 31, 2013 (consisting of both the second year impact of the stipulated four-year amortization of the historical under-recovered NUG balances and the going-forward cost recovery of all the other charges for the period June 1, 2013 through May 31, 2014, and including associated changes in sales-and-use taxes) is an overall annual rate increase of approximately $52.2 million (this rate increase is in addition to the approximately $55.3 million approved by the NJBPU in June 2012, as discussed in the above paragraph). The rates were deemed "provisional" because ACE's filing has not been updated for actual revenues and expenses for April and May 2013. A review by NJBPU of the final underlying costs for reasonableness and prudence will be completed. On June 11, 2013, this matter was transmitted to the OAL for hearing, which has been scheduled for December 2013.

Service Extension Contributions Refund Order

On July 19, 2013, in compliance with a 2012 Appellate Division of New Jersey court decision, the NJBPU released an order requiring utilities to issue refunds to persons or entities that paid non-refundable contributions for service extensions to certain areas described as "Areas Not Designated for Growth." The order is limited to eligible contributions paid between March 20, 2005 and December 20, 2009. ACE is processing the refund requests that meet the eligibility criteria established in the order as they are received. A stakeholder process has been initiated by the NJBPU to amend its rules regarding these types of service extensions (the Main Extension Rules) as a result of the Appellate Division's decision. The stakeholder process is expected to result in a final rulemaking that will amend the Main Extension Rules and address remaining issues related to the refund of these contributions, including deadlines for submission of refund requests. Although ACE believes it received approximately $11 million of contributions between March 20, 2005 and December 20, 2009, it is currently unable to reasonably estimate the amount that it may be required to refund using the eligibility criteria established by the order. At this time, ACE does not expect any such amount refunded will have a material effect on its consolidated financial condition, results of operations or cash flows, as any amounts that may be refunded will generally increase the value of ACE's property, plant and equipment and may ultimately be recovered through depreciation and cost of service.

Generic Consolidated Tax Adjustment Proceeding

In January 2013, the NJBPU initiated a generic proceeding to examine whether a consolidated tax adjustment (CTA) should continue to be used, and if so, how it should be calculated in determining a utility's cost of service. Under the current NJPBU policy related to the CTA, when a New Jersey utility is included in a consolidated group income tax return, an allocated amount of any reduction in the consolidated group's taxes as a result of losses by affiliates is used to reduce the utility's rate base, upon which the utility earns a return. Consequently, the NJBPU's current policy related to the CTA would substantially reduce ACE's rate base and ACE's position is that the CTA should be eliminated. A stakeholder process has been initiated by the NJBPU to aid in this examination. No formal schedule has been set for the remainder of the proceeding or for the issuance of a decision.

Federal Energy Regulatory Commission

On October 17, 2013, the Federal Energy Regulatory Commission (FERC) issued a ruling on challenges filed by the Delaware Electric Municipal Corporation to DPL's 2011 and 2012 annual formula rate updates. In 2006, FERC approved a formula rate for DPL that is incorporated into the PJM tariff. The formula rate establishes the treatment of costs and revenues and the resulting rates for DPL. Pursuant to the protocols approved by FERC and after a period of discovery, interested parties have an opportunity to file challenges regarding the application of the formula rate. The FERC order sets various issues in this proceeding for hearing, including challenges regarding formula rate inputs, deferred income items, prepayments of estimated income taxes, rate base reductions, various administrative and general expenses and the inclusion in rate base of CWIP related to the Mid-Atlantic Power Pathway (MAPP) project (which has been abandoned). Settlement discussions began in this matter on November 5, 2013 before an administrative law judge at FERC.

MPSC New Generation Contract Requirement

In September 2009, the MPSC initiated an investigation into whether Maryland EDCs should be required to enter into long-term contracts with entities that construct, acquire or lease, and operate, new electric generation facilities in Maryland.

In April 2012, the MPSC issued an order determining that there is a need for one new power plant in the range of 650 to 700 MW beginning in 2015. The order requires Pepco, DPL and Baltimore Gas and Electric Company (BGE) (collectively, the Contract EDCs) to negotiate and enter into a contract with the winning bidder of a competitive bidding process in amounts proportional to their relative Standard Offer Service (SOS) loads. Under the contract, the winning bidder will construct a 661 MW natural gas-fired combined cycle generation plant in Waldorf, Maryland, with an expected commercial operation date of June 1, 2015. The order acknowledged the Contract EDCs' concerns about the requirements of the contract and directed them to negotiate with the winning bidder and submit any proposed changes in the contract to the MPSC for approval. The order further specified that the Contract EDCs will recover the associated costs through surcharges on their respective SOS customers.

In April 2012, a group of generating companies operating in the PJM region filed a complaint in the U.S. District Court for the District of Maryland challenging the MPSC's order on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. In May 2012, the Contract EDCs and other parties filed notices of appeal in circuit courts in Maryland requesting judicial review of the MPSC's order. These circuit court appeals were consolidated in the Circuit Court for Baltimore City.

On April 16, 2013, the MPSC issued an order approving a final form of the contract and directing the Contract EDCs to enter into the contract with the winning bidder in amounts proportional to their relative SOS loads. On June 4, 2013, Pepco and DPL each entered into identical contracts in accordance with the terms of the MPSC's order; however, under each contract's own terms, it will not become effective, if at all, until all legal proceedings related to these contracts and the actions of the MPSC in the related proceeding have been resolved.

On September 30, 2013, the U.S. District Court for the District of Maryland issued a ruling that the MPSC's April 2012 order violated the Supremacy Clause of the U.S. Constitution by attempting to regulate wholesale prices. In contrast, on October 1, 2013, the Maryland Circuit Court for Baltimore City upheld the MPSC's orders requiring the Contract EDCs to enter into the contracts.

On October 24, 2013, the Federal district court issued an order ruling that the contracts are illegal and unenforceable. The Federal district court order and its associated ruling could impact the state circuit court appeal, to which the Contract EDCs are parties, although such impact, if any, cannot be determined at this time. PHI expects the Federal district court decision to be appealed. The Contract EDCs also will likely appeal the state court decision to the Maryland Court of Special Appeals.

Assuming the contracts, as currently written, were to become effective by the expected commercial operation date of June 1, 2015, PHI continues to believe that Pepco and DPL may be required to account for their proportional share of the contracts as a derivative instrument at fair value with an offsetting regulatory asset because they would recover any payments under the contracts from SOS customers. In such event, PHI estimates that Pepco and DPL would be required to record an aggregate derivative liability ranging from $55 million to $70 million, with an offsetting regulatory asset in a like amount. This estimated range and the related assumptions may change prior to the time that the contracts become effective, if at all. PHI, Pepco and DPL have concluded that any accounting for these contracts would not be required until all legal proceedings related to these contracts and the actions of the MPSC in the related proceeding have been resolved.

PHI, Pepco and DPL are evaluating these proceedings to determine (i) the extent of the negative effect that the contracts for new generation may have on PHI's, Pepco's and DPL's respective credit metrics, as calculated by independent rating agencies that evaluate and rate PHI, Pepco and DPL and each of their debt issuances, (ii) the effect on Pepco's and DPL's ability to recover their associated costs of the contracts for new generation if a significant number of SOS customers elect to buy their energy from alternative energy suppliers, and (iii) the effect of the contracts on the financial condition, results of operations and cash flows of each of PHI, Pepco and DPL.

Resiliency Task Forces

In July 2012, the Maryland governor signed an Executive Order directing his energy advisor, in collaboration with certain state agencies, to solicit input and recommendations from experts on how to improve the resiliency and reliability of the electric distribution system in Maryland. The resulting Grid Resiliency Task Force issued its report in September 2012, in which it made 11 recommendations. The governor forwarded the report to the MPSC in October 2012, urging the MPSC to quickly implement the first four recommendations: (i) strengthen existing reliability and storm restoration regulations; (ii) accelerate the investment necessary to meet the enhanced metrics; (iii) allow surcharge recovery for the accelerated investment; and (iv) implement clearly defined performance metrics into the traditional ratemaking scheme. Pepco's electric distribution base rate case filed with the MPSC on November 30, 2012 and DPL's electric distribution base rate case filed with the MPSC on March 29, 2013, each attempted to address the Grid Resiliency Task Force recommendations. In July and August 2013, the MPSC issued orders in the Pepco and DPL Maryland electric distribution base rate cases, respectively, that only partially approved the proposed Grid Resiliency Charge. See "Rate Proceedings – Maryland" above for more information about these base rate cases.

In August 2012, the District of Columbia mayor issued an Executive Order establishing the Mayor's Power Line Undergrounding Task Force (the DC Undergrounding Task Force). The stated purpose of the DC Undergrounding Task Force was to pool the collective resources available in the District of Columbia to produce an analysis of the technical feasibility, infrastructure options and reliability implications of undergrounding new or existing overhead distribution facilities in the District of Columbia. These resources included legislative bodies, regulators, utility personnel, experts and other parties who could contribute in a meaningful way to the DC Undergrounding Task Force. The options that are available for financing these efforts were also to be evaluated to identify required legislative or regulatory actions to implement these recommendations. On May 13, 2013, the DC Undergrounding Task Force issued a written recommendation endorsing a $1 billion plan of the DC Undergrounding Task Force to bury 60 of the District of Columbia's most outage-prone power lines. Under this recommendation, (i) Pepco would fund approximately $500 million of the $1 billion estimated cost to complete this project, recovering those costs through surcharges on the electric bills of Pepco District of Columbia customers; (ii) $375 million of the undergrounding project cost would be financed by the District of Columbia's issuance of securitized bonds, which bonds would be repaid through surcharges on the electric bills of Pepco District of Columbia customers (Pepco would not earn a return on the underground lines paid for with the proceeds received from the issuance of the bonds, but those lines would be transferred to Pepco to operate and maintain); and (iii) the remaining amount would be funded through the District of Columbia Department of Transportation's existing capital projects program. Legislation providing for implementation of the report's recommendation was introduced in the Council of the District of Columbia on July 10, 2013. This legislation is expected to be voted upon by the City Council during the fourth quarter of 2013. Once the bill is passed by the City Council, it requires approval of the District of Columbia Mayor and a 30-day Congressional review period before becoming law, which is expected to occur in the first quarter of 2014. The final step would be DCPSC approval of the underground project plan and a DCPSC order approving the financing orders required by the legislation that establishes the customer surcharges to recover Pepco's portion of the undergrounding costs and the repayment of the District of Columbia's securitized bonds, a decision on which is expected during the third quarter of 2014.

ACE Standard Offer Capacity Agreements

In April 2011, ACE entered into three SOCAs by order of the NJBPU, each with a different generation company, as more fully described in Note (2), “Significant Accounting Policies – Consolidation of Variable Interest Entities – ACE Standard Offer Capacity Agreements” and Note (12), “Derivative Instruments and Hedging Activities.” ACE and the other New Jersey EDCs entered into the SOCAs under protest, arguing that the EDCs were denied due process and that the SOCAs violate certain of the requirements under the New Jersey law under which the SOCAs were established (the NJ SOCA Law). On October 22, 2013, in light of the decision of the U.S. District Court for the District of New Jersey described below, the Appellate Division dismissed the appeals filed by the EDCs and generators, without prejudice subject to the parties exercising their appellate rights in the Federal courts.

In February 2011, ACE joined other plaintiffs in an action filed in the U.S. District Court for the District of New Jersey challenging the NJ SOCA Law on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. On October 11, 2013, the Federal district court issued a ruling that the NJ SOCA Law is preempted by the Federal Power Act and violates the Supremacy Clause, and is therefore null and void. On October 21, 2013, a joint motion to stay the Federal district court’s decision pending appeal was filed by the NJBPU and one of the SOCA generation companies. In that motion, the NJBPU notified the Federal district court that it would take no action to force implementation of the SOCAs pending the appeal or such other action – such as FERC approval of the SOCAs – that would cure the constitutional issues to the Federal district court’s satisfaction. On October 25, 2013, the Federal district court issued an order denying the joint motion to stay and ruling that the SOCAs are void, invalid and unenforceable. On October 31, 2013, one of the SOCA generation companies filed a notice of appeal of the October 25, 2013 Federal district court decision. PHI expects the October 11, 2013 and October 25, 2013 decisions to be appealed by the NJBPU and possibly by the other SOCA generation company. In light of the Federal district court order, ACE expects to derecognize in the fourth quarter of 2013 both the derivative asset (liability) for the estimated fair value of the SOCAs and the offsetting regulatory liability (asset).

One of the three SOCAs was terminated effective July 1, 2013 because of an event of default of the generation company that was a party to the SOCA.

MAPP Project

On August 24, 2012, the board of PJM terminated MAPP project and removed it from PJM’s regional transmission expansion plan. PHI had been directed to construct the MAPP project, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region’s transmission system. In December 2012, PHI submitted a filing to FERC seeking recovery of approximately $88 million of abandoned MAPP costs over a five-year recovery period. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

Various protests were submitted in response to PHI’s December 2012 filing, arguing, among other things, that FERC should disallow a portion of the rate of return involving an incentive adder that would be applied to the abandoned costs, and requesting a hearing on various issues such as the amount of the ROE and the prudence of the costs. On February 28, 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of Pepco and DPL, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs. FERC reduced the ROE applicable to the abandoned costs from the previously approved 12.8% incentive ROE to 10.8% by disallowing 200 basis points of ROE adders. FERC also denied recovery of 50% (calculated by PHI to be approximately $2 million), of the prudently incurred abandoned costs prior to November 1, 2008, the date of FERC’s MAPP incentive order. PHI believes that the February 2013 FERC order is not consistent with prior precedent and is vigorously pursuing its rights to recover all prudently incurred abandoned costs associated with the MAPP project, as well as the full ROE previously approved by FERC. On April 1, 2013, PHI filed a rehearing request of the February 28, 2013 FERC order challenging the reduction of the ROE applicable to the abandoned costs, as well as the denial of 50% of the costs incurred prior to November 1, 2008. On that same date, a group of public advocates from Maryland, Delaware, New Jersey, Virginia, West Virginia and Pennsylvania also filed a rehearing request challenging the 10.8% ROE authorized in FERC's order, arguing that PHI is not entitled to any rate of return on the abandoned costs and that FERC improperly failed to set the ROE for hearing. PHI is currently engaged in settlement negotiations in this matter; however, PHI cannot predict when a final FERC decision in this proceeding will be issued.

As of September 30, 2013, PHI had a regulatory asset related to the MAPP abandoned costs of approximately $71 million, representing the original filing amount of approximately $88 million of abandoned costs referred to above less: (i) approximately $2 million of disallowed costs written off in 2013; (ii) $5 million of materials transferred to inventories for use on other projects; and (iii) $10 million of amortization expense recorded in 2013. The regulatory asset balance includes the costs of land, land rights, engineering and design, environmental services, and project management and administration. PHI intends to reduce further the amount of the regulatory asset by any amounts recovered from the sale or alternative use of the land.

Transmission ROE Challenge

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Electric Municipal Corporation, Inc., filed a joint complaint with FERC against Pepco, DPL and ACE, as well as BGE. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that PHI's utilities provide. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for PHI's utilities is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. PHI, Pepco, DPL and ACE believe the allegations in this complaint are without merit and are vigorously contesting it. On April 3, 2013, Pepco, DPL and ACE filed their answer to this complaint, requesting that FERC dismiss the complaint against them on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable.

(8) PENSION AND OTHER POSTRETIREMENT BENEFITS

The following Pepco Holdings information is for the three months ended September 30, 2013 and 2012:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
	(millions of dollars)			
Service cost	$ 14	$ 8	$ 2	$ 2
Interest cost	25	27	6	9
Expected return on plan assets	(36)	(33)	(5)	(5)
Amortization of prior service cost (benefit)	—	1	(4)	(1)
Amortization of net actuarial loss	16	16	2	4
Net periodic benefit cost	$ 19	$ 19	$ 1	$ 9

The following Pepco Holdings information is for the nine months ended September 30, 2013 and 2012:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
	(millions of dollars)			
Service cost	$ 40	$ 26	$ 6	$ 6
Interest cost	75	80	22	26
Expected return on plan assets	(109)	(99)	(15)	(14)
Amortization of prior service cost (benefit)	1	2	(6)	(3)
Amortization of net actuarial loss	50	48	10	11
Termination benefits	—	—	—	1
Net periodic benefit cost	$ 57	$ 57	$ 17	$ 27

Pension and Other Postretirement Benefits

Net periodic benefit cost related to continuing operations is included in other operation and maintenance expense, net of the portion of the net periodic benefit cost that is capitalized as part of the cost of labor for internal construction projects. After intercompany allocations, the three utility subsidiaries are responsible for substantially all of the total PHI net periodic pension and other postretirement benefit costs related to continuing operations.

Pension Contributions

PHI’s funding policy with regard to PHI’s non-contributory retirement plan (the PHI Retirement Plan) is to maintain a funding level that is at least equal to the target liability as defined under the Pension Protection Act of 2006. In the second quarter of 2013, PHI made a discretionary tax-deductible contribution to the PHI Retirement Plan in the amount of $60 million. In the first quarter of 2013, PHI, DPL and ACE made discretionary tax-deductible contributions to the PHI Retirement Plan in the amounts of $20 million, $10 million and $30 million, respectively. In the first quarter of 2012, Pepco, DPL and ACE made discretionary tax-deductible contributions to the PHI Retirement Plan in the amounts of $85 million, $85 million and $30 million, respectively, which brought the PHI Retirement Plan assets to the funding target level for 2012 under the Pension Protection Act.

Other Postretirement Benefit Plan Amendment

During 2013, PHI approved two amendments to its other postretirement benefits plan. These amendments impacted the retiree medical plan and the retiree life insurance benefits, and will be effective on January 1, 2014. As a result of the amendments, which were cumulatively significant, PHI remeasured its projected benefit obligation for other postretirement benefits as of July 1, 2013. The remeasurement resulted in a $193 million reduction of the projected benefit obligation, which included recording a prior service credit of $124 million, which will be amortized over approximately ten years, and a $69 million reduction from a change in the discount rate from 4.10% as of December 31, 2012 to 4.95% as of July 1, 2013. The remeasurement is expected to result in a $13 million reduction in net periodic benefit cost for other postretirement benefits during 2013. Approximately 30% of net periodic other postretirement benefit costs are capitalized.

(9) DEBT

Credit Facility

PHI, Pepco, DPL and ACE maintain an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. On August 1, 2011, PHI, Pepco, DPL and ACE entered into an amended and restated credit agreement which, on August 2, 2012, was amended to extend the term of the credit facility to August 1, 2017 and to amend the pricing schedule to decrease certain fees and interest rates payable to the lenders under the facility. On June 6, 2013, as permitted under the existing terms of the credit agreement, PHI, Pepco, DPL and ACE provided to the agent and lenders under the credit agreement, a notice requesting a one-year extension of the credit facility termination date. The request was approved and the new termination date is August 1, 2018. All of the terms and conditions as well as pricing remain the same.

The aggregate borrowing limit under the amended and restated credit facility is $1.5 billion, all or any portion of which may be used to obtain loans and up to $500 million of which may be used to obtain letters of credit. The facility also includes a swingline loan sub-facility, pursuant to which each company may make same day borrowings in an aggregate amount not to exceed 10% of the total amount of the facility. Any swingline loan must be repaid by the borrower within fourteen days of receipt. The credit sublimit is $750 million for PHI and $250 million for each of Pepco, DPL and ACE. The sublimits may be increased or decreased by the individual borrower during the term of the facility, except that (i) the sum of all of the borrower sublimits following any such increase or decrease must equal the total amount of the facility and (ii) the aggregate amount of credit used at any given time by (a) PHI may not exceed $1.25 billion and (b) each of Pepco, DPL or ACE may not exceed the lesser of $500 million and the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the sublimit reallocations may not exceed eight per year during the term of the facility.

The interest rate payable by each company on utilized funds is, at the borrowing company's election, (i) the greater of the prevailing prime rate, the federal funds effective rate plus 0.5% and the one month London Interbank Offered Rate (LIBOR) plus 1.0%, or (ii) the prevailing Eurodollar rate, plus a margin that varies according to the credit rating of the borrower.

In order for a borrower to use the facility, certain representations and warranties must be true and correct, and the borrower must be in compliance with specified financial and other covenants, including (i) the requirement that each borrowing company maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the credit agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) with certain exceptions, a restriction on sales or other dispositions of assets, and (iii) a restriction on the incurrence of liens on the assets of a borrower or any of its significant subsidiaries other than permitted liens. The credit agreement contains certain covenants and other customary agreements and requirements that, if not complied with, could result in an event of default and the acceleration of repayment obligations of one or more of the borrowers thereunder. Each of the borrowers was in compliance with all covenants under this facility as of September 30, 2013.

The absence of a material adverse change in PHI's business, property, results of operations or financial condition is not a condition to the availability of credit under the credit agreement. The credit agreement does not include any rating triggers.

As of September 30, 2013 and December 31, 2012, the amount of cash plus unused borrowing capacity under the credit facility available to meet the future liquidity needs of PHI and its utility subsidiaries on a consolidated basis totaled $1,256 million and $861 million, respectively. PHI's utility subsidiaries had combined cash and unused borrowing capacity under the credit facility of $471 million and $477 million at September 30, 2013 and December 31, 2012, respectively.

Commercial Paper

PHI, Pepco, DPL and ACE maintain on-going commercial paper programs to address short-term liquidity needs. As of September 30, 2013, the maximum capacity available under these programs was $875 million, $500 million, $500 million and $250 million, respectively, subject to available borrowing capacity under the credit facility.

PHI, Pepco, DPL and ACE had zero, $32 million, $150 million and $99 million, respectively, of commercial paper outstanding at September 30, 2013. The weighted average interest rate for commercial paper issued by PHI, Pepco, DPL and ACE during the nine months ended September 30, 2013 was 0.70%, 0.37%, 0.29% and 0.32%, respectively. The weighted average maturity of all commercial paper issued by PHI, Pepco, DPL and ACE during the nine months ended September 30, 2013 was five, six, three and four days, respectively.

Other Financing Activities

PHI Term Loan Agreement

On March 28, 2013, PHI entered into a $250 million term loan agreement due March 27, 2014, pursuant to which PHI had borrowed $250 million at a rate of interest equal to the prevailing Eurodollar rate, which is determined by reference to the LIBOR with respect to the relevant interest period, all as defined in the loan agreement, plus a margin of 0.875%. PHI used the net proceeds of the loan under the loan agreement to repay the outstanding $200 million term loan obtained in 2012, and for general corporate purposes. On May 29, 2013, PHI repaid the $250 million term loan with a portion of the net proceeds from the early termination of the cross-border energy lease investments.

ACE Term Loan Agreement

On May 10, 2013, ACE entered into a $100 million term loan agreement, pursuant to which ACE has borrowed (and may not re-borrow) $100 million at a rate of interest equal to the prevailing Eurodollar rate, which is determined by reference to the LIBOR with respect to the relevant interest period, all as defined in the loan agreement, plus a margin of 0.75%. ACE's Eurodollar borrowings under the loan agreement may be converted into floating rate loans under certain circumstances, and, in that event, for so long as any loan remains a floating rate loan, interest would accrue on that loan at a rate per year equal to (i) the highest of (a) the prevailing prime rate, (b) the federal funds effective rate plus 0.5%, or (c) the one-month Eurodollar rate plus 1%, plus (ii) a margin of 0.75%. As of September 30, 2013, outstanding borrowings under the loan agreement bore interest at an annual rate of 0.94%, which is subject to adjustment from time to time. All borrowings under the loan agreement are unsecured, and the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement, must be repaid in full on or before November 10, 2014.

Under the terms of the term loan agreement, ACE must maintain compliance with specified covenants, including (i) the requirement that ACE maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the loan agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) a restriction on sales or other dispositions of assets, other than certain permitted sales and dispositions, and (iii) a restriction on the incurrence of liens (other than liens permitted by the loan agreement) on the assets of ACE. The loan agreement does not include any rating triggers. ACE was in compliance with all covenants under this loan agreement as of September 30, 2013.

Bond Payments

In July 2013, ACE Funding made principal payments of $7 million on its Series 2002-1 Bonds, Class A-3, and $2 million on its Series 2003-1 Bonds, Class A-2.

Bond Retirement

On August 1, 2013, ACE repaid at maturity $68.6 million of its 6.625% non-callable first mortgage bonds.

Financing Activities Subsequent to September 30, 2013

Bond Payments

In October 2013, ACE Funding made principal payments of $8 million on its Series 2002-1 Bonds, Class A-3, and $3 million on its Series 2003-1 Bonds, Class A-2.

Long-Term Project Funding

On October 24, 2013, Pepco Energy Services entered into an agreement with a lender to receive up to $8 million in construction financing at an interest rate of 4.68% for an energy savings project that is expected to be completed in 2014. The agreement includes a transfer of receivables from Pepco Energy Services to the lender after construction is completed, under which the customer would make contractual payments over a 23-year period to repay the financing. If there are shortfalls in Pepco Energy Services' energy savings guarantee or other performance obligations to the customer that reduce customer payments below the contractual payment amounts, then Pepco Energy Services would compensate the lender for the unpaid amounts. PHI has guaranteed the performance obligations of Pepco Energy Services under the financing agreement.

(10) INCOME TAXES

A reconciliation of PHI's consolidated effective income tax rates from continuing operations is as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2013		2012		2013		2012	
	(millions of dollars)							
Income tax at Federal statutory rate	$ 61	35.0%	$ 51	35.0%	$116	35.0%	$ 97	35.0%
Increases (decreases) resulting from:								
State income taxes, net of Federal effect	11	6.3%	9	6.3%	21	6.3%	19	6.9%
Asset removal costs	(5)	(2.9)%	(1)	(0.7)%	(11)	(3.3)%	(8)	(2.9)%
Change in estimates and interest related to uncertain and effectively settled tax positions	1	0.6%	—	—	55	16.6%	(10)	(3.6)%
Establishment of valuation allowances related to deferred tax assets	—	—	—	—	101	30.4%	—	—
Other, net	(3)	(1.9)%	(2)	(1.0)%	(2)	(0.7)%	(6)	(2.1)%
Consolidated income tax expense related to continuing operations	$ 65	37.1%	$ 57	39.6%	$280	84.3%	$ 92	33.3%

Three Months Ended September 30, 2013 and 2012

PHI's consolidated effective tax rates for the three months ended September 30, 2013 and 2012 were 37.1% and 39.6%, respectively. The decrease in the effective tax rate primarily resulted from an increase in asset removal costs.

Nine Months Ended September 30, 2013 and 2012

PHI's consolidated effective tax rates for the nine months ended September 30, 2013 and 2012 were 84.3% and 33.3%, respectively.

The increase in the effective tax rate for the nine months ended September 30, 2013 occurred as a result of recording $55 million of changes in estimates and interest related to uncertain and effectively settled tax positions in the first quarter of 2013. In addition, the increase in the effective tax rate resulted from the establishment of valuation allowances of $101 million in the first quarter of 2013 against certain deferred tax assets in Corporate and Other. Between 1990 and 1999, PCI, through various subsidiaries, entered into certain transactions involving investments in aircraft and aircraft equipment, railcars and other assets. In connection with these transactions, PCI recorded deferred tax assets in prior years of $101 million in the aggregate. Following events that took place during the first quarter of 2013, which included (i) court decisions in favor of the Internal Revenue Service (IRS) with respect to both Consolidated Edison's cross-border lease transaction (as discussed in Note (16), "Discontinued Operations – Cross-Border Energy Lease Investments") and another taxpayer's structured transactions, (ii) the change in PHI's tax position with respect to the tax benefits associated with its cross-border energy leases and (iii) PHI's decision in March 2013 to begin to pursue the early termination of its remaining cross-border energy lease investments (which represented a substantial portion of the remaining assets within PCI) without the intent to reinvest these proceeds in income-producing assets, management evaluated the likelihood that PCI will be able to realize the $101 million of deferred tax assets in the future. Based on this evaluation, PCI established valuation allowances against these deferred tax assets totaling $101 million in the first quarter of 2013.

In 2012, PHI's effective tax rate was impacted by the effective settlement with the IRS in the first quarter of 2012 with respect to the methodology used historically to calculate deductible mixed service costs and the expiration of the statute of limitations associated with an uncertain tax position in Pepco.

Final IRS Regulations on Repair of Tangible Property

In September 2013, the IRS issued final regulations on expense versus capitalization of repairs with respect to tangible personal property. The regulations are effective for tax years beginning on or after January 1, 2014, and provide an option to early adopt the final regulations for tax years beginning on or after January 1, 2012. It is expected that the IRS will issue revenue procedures that will describe how taxpayers may implement the final regulations. The final repair regulations retain the operative rule that the Unit of Property for network assets is determined by the taxpayer's particular facts and circumstances except as provided in published guidance. In 2012, with the filing of its 2011 tax return, PHI filed a request for an automatic change in accounting method related to repairs of its network assets in accordance with IRS Revenue Procedure 2011-43. PHI does not expect the effects of the final regulations to be significant and will continue to evaluate the impact of the new guidance on its consolidated financial statements.

(11) EQUITY AND EARNINGS PER SHARE

Basic and Diluted Earnings Per Share

PHI's basic and diluted earnings per share (EPS) calculations are shown below:

	Three Months Ended September 30, 2013	2012
	(millions of dollars, except per share data)	
Income (Numerator):		
Net Income from continuing operations	$ 110	$ 87
Net Income from discontinued operations	8	25
Net Income	$ 118	$ 112
Shares (Denominator) (in millions):		
Weighted average shares outstanding for basic computation:		
Average shares outstanding	249	229
Adjustment to shares outstanding	—	—
Weighted Average Shares Outstanding for Computation of Basic Earnings Per Share of Common Stock	249	229
Net effect of potentially dilutive shares (a)	—	2
Weighted Average Shares Outstanding for Computation of Diluted Earnings Per Share of Common Stock	249	231
Basic and Diluted Earnings per Share		
Earnings per share of common stock from continuing operations	$ 0.44	$ 0.38
Earnings per share of common stock from discontinued operations	0.04	0.11
Basic and diluted earnings per share	$ 0.48	$ 0.49

(a) There were no options to purchase shares of common stock that were excluded from the calculation of diluted EPS for the three months ended September 30, 2013 and 2012.

	Nine Months Ended September 30, 2013	2012
	(millions of dollars, except per share data)	
Income (Numerator):		
Net Income from continuing operations	$ 52	$ 184
Net (Loss) Income from discontinued operations	(322)	58
Net (Loss) Income	$ (270)	$ 242
Shares (Denominator) (in millions):		
Weighted average shares outstanding for basic computation:		
Average shares outstanding	245	228
Adjustment to shares outstanding	—	—
Weighted Average Shares Outstanding for Computation of Basic Earnings Per Share of Common Stock	245	228
Net effect of potentially dilutive shares (a)	—	1
Weighted Average Shares Outstanding for Computation of Diluted Earnings Per Share of Common Stock	245	229
Basic and Diluted Earnings per Share		
Earnings per share of common stock from continuing operations	$ 0.21	$ 0.80
(Loss) Earnings per share of common stock from discontinued operations	(1.31)	0.26
Basic and diluted (loss) earnings per share	$ (1.10)	$ 1.06

(a) There were no options to purchase shares of common stock that were excluded from the calculation of diluted EPS for the nine months ended September 30, 2013 and 2012.

Equity Forward Transaction

During 2012, PHI entered into an equity forward transaction in connection with a public offering of PHI common stock. Pursuant to the terms of this transaction, a forward counterparty borrowed 17,922,077 shares of PHI's common stock from third parties and sold them to a group of underwriters for $19.25 per share, less an underwriting discount equal to $0.67375 per share. Under the terms of the equity forward transaction, upon physical settlement thereof, PHI was required to issue and deliver shares of PHI common stock to the forward counterparty at the then applicable forward sale price. The forward sale price was initially determined to be $18.57625 per share at the time the equity forward transaction was entered into and was subject to reduction from time to time in accordance with the terms of the equity forward transaction. PHI believed that the equity forward transaction substantially eliminated future equity price risk because the forward sale price was determinable as of the date that PHI entered into the equity forward transaction and was only reduced pursuant to the contractual terms of the equity forward transaction through the settlement date, which reductions were not affected by a future change in the market price of the PHI common stock. On February 27, 2013, PHI physically settled the equity forward at the then applicable forward sale price of $17.39 per share. The proceeds of approximately $312 million were used to repay outstanding commercial paper, a portion of which had been issued in order to make capital contributions to the utilities, and for general corporate purposes.

Treasury Stock

Premium on stock and other capital contributions on PHI's consolidated balance sheet at March 31, 2013 included approximately $2 million of treasury stock outstanding, representing 102,933 shares with a weighted-average price of $19.93. These shares were repurchased during the first quarter of 2013 to cover minimum withholding taxes of certain participants in PHI's Long-Term Incentive Plan and were reissued during the first and second quarters of 2013 to participants in the PHI Retirement Savings Plan.

(12) DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Derivatives are used by Power Delivery to hedge commodity price risk, as well as by PHI, from time to time, to hedge interest rate risk.

DPL uses derivative instruments in the form of swaps and over-the-counter options primarily to reduce natural gas commodity price volatility and to limit its customers' exposure to increases in the market price of natural gas under a hedging program approved by the DPSC. DPL uses these derivatives to manage the commodity price risk associated with its physical natural gas purchase contracts. All premiums paid and other transaction costs incurred as part of DPL's natural gas hedging activity, in addition to all gains and losses related to hedging activities, are deferred under FASB guidance on regulated operations (ASC 980) until recovered from its customers through a fuel adjustment clause approved by the DPSC. The natural gas purchase contracts qualify as normal purchases, which are not required to be recorded in the financial statements until settled.

ACE was ordered to enter into the SOCAs by the NJBPU, and under the SOCAs, ACE would receive payments from or make payments to electric generation facilities based on i) the difference between the fixed price in the SOCAs and the price for capacity that clears PJM and ii) ACE's annual proportion of the total New Jersey load relative to the other EDCs in New Jersey, which is currently estimated to be approximately 15 percent. ACE began applying derivative accounting to two of its SOCAs as of June 30, 2012 because the generators cleared the 2015-2016 PJM capacity auction in May 2012. In May 2013, all three generation companies under the SOCAs bid into the PJM 2016-2017 capacity auction. Two of the generators cleared the capacity auction, while the third did not. On July 1, 2013, the SOCA with the third generation company was terminated as the generation company did not clear a PJM capacity auction by the commencement date required under the SOCA. The fair value of the derivatives embedded in the SOCAs are deferred as regulatory assets or regulatory liabilities because the NJBPU has allowed full recovery from ACE's distribution customers for all payments made by ACE, and ACE's distribution customers would be entitled to all payments received by ACE. As further discussed in Note (7), "Regulatory Matters," in light of a Federal district court order issued on October 25, 2013, ACE expects to derecognize in the fourth quarter of 2013, the derivative asset of $4 million and the derivative liability of $14 million as of September 30, 2013 related to the SOCAs reflected in the table below, as well as the offsetting regulatory liability (asset).

PHI also uses derivative instruments from time to time to mitigate the effects of fluctuating interest rates on debt issued in connection with the operation of its businesses. In June 2002, PHI entered into several treasury rate lock transactions in anticipation of the issuance of several series of fixed-rate debt commencing in August 2002. Upon issuance of the fixed rate-debt in August 2002, the treasury rate locks were terminated at a loss. The loss has been deferred in Accumulated Other Comprehensive Loss (AOCL) and is being recognized in income over the life of the debt issued as interest payments are made.

The tables below identify the balance sheet location and fair values of derivative instruments as of September 30, 2013 and December 31, 2012:

Balance Sheet Caption	As of September 30, 2013 Derivatives Designated as Hedging Instruments	Other Derivative Instruments	Gross Derivative Instruments	Effects of Cash Collateral and Netting	Net Derivative Instruments
	(millions of dollars)				
Derivative assets (non-current assets)	$ —	$ 4	$ 4	$ —	$ 4
Total Derivative assets	—	4	4	—	4
Derivative liabilities (current liabilities)	—	(1)	(1)	1	—
Derivative liabilities (non-current liabilities)	—	(14)	(14)	—	(14)
Total Derivative liabilities	—	(15)	(15)	1	(14)
Net Derivative (liability) asset	$ —	$ (11)	$ (11)	$ 1	$ (10)

Balance Sheet Caption	As of December 31, 2012 Derivatives Designated as Hedging Instruments	Other Derivative Instruments	Gross Derivative Instruments	Effects of Cash Collateral and Netting	Net Derivative Instruments
	(millions of dollars)				
Derivative assets (non-current assets)	$ —	$ 8	$ 8	$ —	$ 8
Total Derivative assets	—	8	8	—	8
Derivative liabilities (current liabilities)	—	(4)	(4)	—	(4)
Derivative liabilities (non-current liabilities)	—	(11)	(11)	—	(11)
Total Derivative liabilities	—	(15)	(15)	—	(15)
Net Derivative (liability) asset	$ —	$ (7)	$ (7)	$ —	$ (7)

Under FASB guidance on the offsetting of balance sheet accounts (ASC 210-20), PHI offsets the fair value amounts recognized for derivative assets and liabilities and the fair value amounts recognized for related collateral positions executed with the same counterparty under master netting agreements. All derivative assets and liabilities available to be offset under master netting arrangements were netted as of September 30, 2013 and December 31, 2012. The amount of cash collateral that was offset against these derivative positions is as follows**:**

	September 30, 2013	December 31, 2012
	(millions of dollars)	
Cash collateral pledged to counterparties with the right to reclaim (a)	$ 1	$ —

(a) Includes cash deposits on commodity brokerage accounts.

As of September 30, 2013 and December 31, 2012, all PHI cash collateral pledged related to derivative instruments accounted for at fair value was entitled to be offset under master netting agreements.

Derivatives Designated as Hedging Instruments

Cash Flow Hedges

Cash Flow Hedges Included in Accumulated Other Comprehensive Loss

The tables below provide details regarding effective cash flow hedges included in PHI's consolidated balance sheets as of September 30, 2013 and 2012. Cash flow hedges are marked to market on the consolidated balance sheet with corresponding adjustments to AOCL for the effective portion of cash flow hedges. The data in the following tables indicate the cumulative net loss after-tax related to effective cash flow hedges by contract type included in AOCL, the portion of AOCL expected to be reclassified to income during the next 12 months, and the maximum hedge or deferral term:

Contracts	As of September 30, 2013 Accumulated Other Comprehensive Loss After-tax	As of September 30, 2013 Portion Expected to be Reclassified to Income during the Next 12 Months	Maximum Term
	(millions of dollars)		
Interest rate	$ 9	$ 1	227 months
Total	$ 9	$ 1	

Contracts	As of September 30, 2012 Accumulated Other Comprehensive Loss After-tax	As of September 30, 2012 Portion Expected to be Reclassified to Income during the Next 12 Months	Maximum Term
	(millions of dollars)		
Interest rate	$ 10	$ 1	239 months
Total	$ 10	$ 1	

Other Derivative Activity

DPL and ACE have certain derivatives that are not in hedge accounting relationships and are not designated as normal purchases or normal sales. These derivatives are recorded at fair value on the consolidated balance sheets with the gain or loss for changes in fair value recorded in income. In accordance with FASB guidance on regulated operations, offsetting regulatory liabilities or regulatory assets are recorded on the consolidated balance sheets and the recognition of the derivative gain or loss is deferred because of the DPSC-approved fuel adjustment clause for DPL's derivatives and the NJBPU order pertaining to the SOCAs within which ACE's capacity derivatives are embedded. The following table indicates the net unrealized derivative gains and losses arising during the period that were deferred as regulatory liabilities and regulatory assets, respectively, and the net realized losses recognized in the consolidated statements of income (through Fuel and Purchased Energy expense) that were also deferred as regulatory assets for the three and nine months ended September 30, 2013 and 2012 associated with these derivatives:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(millions of dollars)			
Net unrealized gain (loss) arising during the period	$ —	$ 2	$ (7)	$ (3)
Net realized losses recognized during the period	—	(2)	(3)	(13)

As of September 30, 2013 and December 31, 2012, the quantities and positions of DPL's net outstanding natural gas commodity forward contracts and ACE's capacity derivatives associated with the SOCAs that did not qualify for hedge accounting were:

	September 30, 2013		December 31, 2012	
Commodity	**Quantity**	**Net Position**	**Quantity**	**Net Position**
DPL – Natural gas (one Million British Thermal Units (MMBtu))	3,767,500	Long	3,838,000	Long
ACE – Capacity (MWs)	180	Long	180	Long

Contingent Credit Risk Features

The primary contracts used by the Power Delivery segment for derivative transactions are entered into under the International Swaps and Derivatives Association Master Agreement (ISDA) or similar agreements that closely mirror the principal credit provisions of the ISDA. The ISDAs include a Credit Support Annex (CSA) that governs the mutual posting and administration of collateral security. The failure of a party to comply with an obligation under the CSA, including an obligation to transfer collateral security when due or the failure to maintain any required credit support, constitutes an event of default under the ISDA for which the other party may declare an early termination and liquidation of all transactions entered into under the ISDA, including foreclosure against any collateral security. In addition, some of the ISDAs have cross default provisions under which a default by a party under another commodity or derivative contract, or the breach by a party of another borrowing obligation in excess of a specified threshold, is a breach under the ISDA.

Under the ISDA or similar agreements, the parties establish a dollar threshold of unsecured credit for each party in excess of which the party would be required to post collateral to secure its obligations to the other party. The amount of the unsecured credit threshold varies according to the senior, unsecured debt rating of the respective parties or that of a guarantor of the party's obligations. The fair values of all transactions between the parties are netted under the master netting provisions. Transactions may include derivatives accounted for on-balance sheet as well as those designated as normal purchases and normal sales that are accounted for off-balance sheet. If the aggregate fair value of the transactions in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. The obligations of DPL are stand-alone obligations without the guaranty of PHI. If DPL's debt rating were to fall below "investment grade," the unsecured credit threshold would typically be set at zero and collateral would be required for the entire net loss position. Exchange-traded contracts are required to be fully collateralized without regard to the credit rating of the holder.

The gross fair values of DPL's derivative liabilities with credit risk-related contingent features as of September 30, 2013 and December 31, 2012, were zero and $4 million, respectively, before giving effect to offsetting transactions or collateral under master netting agreements. As of September 30, 2013 and December 31, 2012, DPL had posted no cash collateral against its gross derivative liability, resulting in a net liability of zero and $4 million, respectively. If DPL's debt ratings had been downgraded below investment grade as of September 30, 2013 and December 31, 2012, DPL's net settlement amounts, including both the fair value of its derivative liabilities and its normal purchase and normal sale contracts would have been approximately zero and $2 million, respectively, and DPL would have been required to post collateral with the counterparties of approximately zero and $2 million, respectively, in addition to that which was posted as of September 30, 2013 and December 31, 2012. The net settlement and additional collateral amounts reflect the effect of offsetting transactions under master netting agreements.

DPL's primary source for posting cash collateral or letters of credit is PHI's credit facility. As of September 30, 2013 and December 31, 2012, the aggregate amount of cash plus borrowing capacity under the credit facility available to meet the future liquidity needs of PHI's utility subsidiaries was $471 million and $477 million, respectively.

(13) FAIR VALUE DISCLOSURES

Financial Instruments Measured at Fair Value on a Recurring Basis

PHI applies FASB guidance on fair value measurement and disclosures (ASC 820) that established a framework for measuring fair value and expanded disclosures about fair value measurements. As defined in the guidance, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). PHI utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. Accordingly, PHI utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1) and the lowest priority to unobservable inputs (level 3).

The following tables set forth, by level within the fair value hierarchy, PHI's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2013 and December 31, 2012. As required by the guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. PHI's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Description	Total	Fair Value Measurements at September 30, 2013 Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
		(millions of dollars)		
ASSETS				
Derivative instruments (b)				
Capacity (d)	$ 4	$ —	$ —	$ 4
Cash equivalents				
Treasury fund	69	69	—	—
Executive deferred compensation plan assets				
Money market funds	17	17	—	—
Life insurance contracts	62	—	44	18
	$152	$ 86	$ 44	$ 22
LIABILITIES				
Derivative instruments (b)				
Natural gas (c)	$ 1	$ 1	$ —	$ —
Capacity (d)	14	—	—	14
Executive deferred compensation plan liabilities				
Life insurance contracts	28	—	28	—
	$ 43	$ 1	$ 28	$ 14

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the nine months ended September 30, 2013.
(b) The fair values of derivative assets and liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents natural gas swaps purchased by DPL as part of a natural gas hedging program approved by the DPSC.
(d) Represents derivatives associated with the ACE SOCAs.

Description	Total	Fair Value Measurements at December 31, 2012 Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
		(millions of dollars)		
ASSETS				
Derivative instruments (b)				
Capacity (d)	$ 8	$ —	$ —	$ 8
Cash equivalents				
Treasury fund	27	27	—	—
Executive deferred compensation plan assets				
Money market funds	17	17	—	—
Life insurance contracts	60	—	42	18
	$112	$ 44	$ 42	$ 26
LIABILITIES				
Derivative instruments (b)				
Natural gas (c)	$ 4	$ —	$ —	$ 4
Capacity (d)	11	—	—	11
Executive deferred compensation plan liabilities				
Life insurance contracts	28	—	28	—
	$ 43	$ —	$ 28	$ 15

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2012.
(b) The fair values of derivative assets and liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents natural gas options purchased by DPL as part of a natural gas hedging program approved by the DPSC.
(d) Represents derivatives associated with the ACE SOCAs.

PHI classifies its fair value balances in the fair value hierarchy based on the observability of the inputs used in the fair value calculation as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis, such as the New York Mercantile Exchange (NYMEX).

Level 2 – Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using broker quotes in liquid markets and other observable data. Level 2 also includes those financial instruments that are valued using methodologies that have been corroborated by observable market data through correlation or by other means. Significant assumptions are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Executive deferred compensation plan assets and liabilities categorized as level 2 consist of life insurance policies and certain employment agreement obligations. The life insurance policies are categorized as level 2 assets because they are valued based on the assets underlying the policies, which consist of short-term cash equivalents and fixed income securities that are priced using observable market data and can be liquidated for the value of the underlying assets as of September 30, 2013. The level 2 liability associated with the life insurance policies represents a deferred compensation obligation, the value of which is tracked via underlying insurance sub-accounts. The sub-accounts are designed to mirror existing mutual funds and money market funds that are observable and actively traded.

The value of certain employment agreement obligations (which are included with life insurance contracts in the tables above) is derived using a discounted cash flow valuation technique. The discounted cash flow calculations are based on a known and certain stream of payments to be made over time that are discounted to determine their net present value. The primary variable input, the discount rate, is based on market-corroborated and observable published rates. These obligations have been classified as level 2 within the fair value hierarchy because the payment streams represent contractually known and certain amounts and the discount rate is based on published, observable data.

Level 3 – Pricing inputs that are significant and generally less observable than those from objective sources. Level 3 includes those financial instruments that are valued using models or other valuation methodologies.

Derivative instruments categorized as level 3 include natural gas options used by DPL as part of a natural gas hedging program approved by the DPSC and capacity under the SOCAs entered into by ACE:

- DPL applies a Black-Scholes model to value its options with inputs, such as forward price curves, contract prices, contract volumes, the risk-free rate and implied volatility factors, that are based on a range of historical NYMEX option prices. DPL maintains valuation policies and procedures and reviews the validity and relevance of the inputs used to estimate the fair value of its options. As of September 30, 2013, all of these contracts classified as level 3 derivative instruments have settled.
- ACE used a discounted cash flow methodology to estimate the fair value of the capacity derivatives embedded in the SOCAs. ACE utilized an external valuation specialist to estimate annual zonal PJM capacity prices through the 2030-2031 auction. The capacity price forecast was based on various assumptions that impact the cost of constructing new generation facilities, including zonal load forecasts, zonal fuel and energy prices, generation capacity and transmission planning, and environmental legislation and regulation. ACE reviewed the assumptions and resulting capacity price forecast for reasonableness. ACE used the capacity price forecast to estimate future cash flows. A significant change in the forecasted prices would have a significant impact on the estimated fair value of the SOCAs. ACE employed a discount rate reflective of the estimated weighted average cost of capital for merchant generation companies since payments under the SOCAs are contingent on providing generation capacity.

The tables below summarize the primary unobservable inputs used to determine the fair value of PHI's level 3 instruments and the range of values that could be used for those inputs as of September 30, 2013 and December 31, 2012:

Type of Instrument	Fair Value at September 30, 2013 *(millions of dollars)*	Valuation Technique	Unobservable Input	Range
Capacity contracts, net	$ (10)	Discounted cash flow	Discount rate	5% - 9%

Type of Instrument	Fair Value at December 31, 2012 *(millions of dollars)*	Valuation Technique	Unobservable Input	Range
Natural gas options	$ (4)	Option model	Volatility factor	1.57 - 2.00
Capacity contracts, net	(3)	Discounted cash flow	Discount rate	5% - 9%

PHI used values within these ranges as part of its fair value estimates. A significant change in any of the unobservable inputs within these ranges would have an insignificant impact on the reported fair value as of September 30, 2013 and December 31, 2012.

Executive deferred compensation plan assets include certain life insurance policies that are valued using the cash surrender value of the policies, net of loans against those policies. The cash surrender values do not represent a quoted price in an active market; therefore, those inputs are unobservable and the policies are categorized as level 3. Cash surrender values are provided by third parties and reviewed by PHI for reasonableness.

Reconciliations of the beginning and ending balances of PHI's fair value measurements using significant unobservable inputs (Level 3) for the nine months ended September 30, 2013 and 2012 are shown below:

	Nine Months Ended September 30, 2013		
	Natural Gas	Life Insurance Contracts	Capacity
		(millions of dollars)	
Beginning balance as of January 1	$ (4)	$ 18	$ (3)
Total gains (losses) (realized and unrealized):			
Included in income	—	3	—
Included in accumulated other comprehensive loss	—	—	—
Included in regulatory liabilities and regulatory assets	—	—	(7)
Purchases	—	—	—
Issuances	—	(3)	—
Settlements	4	—	—
Transfers in (out) of level 3	—	—	—
Ending balance as of September 30	$ —	$ 18	$ (10)

	Nine Months Ended September 30, 2012		
	Natural Gas	Life Insurance Contracts	Capacity
		(millions of dollars)	
Beginning balance as of January 1	$ (15)	$ 17	$ —
Total gains (losses) (realized and unrealized):			
Included in income	—	3	—
Included in accumulated other comprehensive loss	—	—	—
Included in regulatory liabilities and regulatory assets	(2)	—	(1)
Purchases	—	—	—
Issuances	—	(3)	—
Settlements	10	—	—
Transfers in (out) of level 3	—	—	—
Ending balance as of September 30	$ (7)	$ 17	$ (1)

The breakdown of realized and unrealized gains on level 3 instruments included in income as a component of Other Income or Other Operation and Maintenance expense for the periods below were as follows:

	Nine Months Ended September 30,	
	2013	2012
	(millions of dollars)	
Total net gains included in income for the period	$ 3	$ 3
Change in unrealized gains relating to assets still held at reporting date	$ 3	$ 3

Other Financial Instruments

The estimated fair values of PHI's debt instruments that are measured at amortized cost in PHI's consolidated financial statements and the associated level of the estimates within the fair value hierarchy as of September 30, 2013 and December 31, 2012 are shown in the tables below. As required by the fair value measurement guidance, debt instruments are classified in their entirety within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. PHI's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, which may affect the valuation of fair value debt instruments and their placement within the fair value hierarchy levels.

The fair value of Long-term debt and Transition Bonds issued by ACE Funding categorized as level 2 is based on a blend of quoted prices for the debt and quoted prices for similar debt on the measurement date. The blend places more weight on current pricing information when determining the final fair value measurement. The fair value information is provided by brokers, and PHI reviews the methodologies and results.

The fair value of Long-term debt categorized as level 3 is based on a discounted cash flow methodology using observable inputs, such as the U.S. Treasury yield, and unobservable inputs, such as credit spreads, because quoted prices for the debt or similar debt in active markets were insufficient. The Long-Term project funding represents debt instruments issued by Pepco Energy Services related to its energy savings contracts. Long-Term project funding is categorized as level 3 because PHI concluded that the amortized cost carrying amounts for these instruments approximates fair value, which does not represent a quoted price in an active market.

	Fair Value Measurements at September 30, 2013			
Description	**Total**	**Quoted Prices in Active Markets for Identical Instruments (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
	(millions of dollars)			
LIABILITIES				
Debt instruments				
Long-term debt (a)	$4,953	$ —	$ 4,387	$ 566
Transition Bonds issued by ACE Funding (b)	299	—	299	—
Long-term project funding	12	—	—	12
	$5,264	$ —	$ 4,686	$ 578

(a) The carrying amount for Long-term debt is $4,457 million as of September 30, 2013.
(b) The carrying amount for Transition Bonds issued by ACE Funding, including amounts due within one year, is $267 million as of September 30, 2013.

Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
	Fair Value Measurements at December 31, 2012 (millions of dollars)			
LIABILITIES				
Debt instruments				
Long-term debt (b)	$5,004	$ —	$ 4,517	$ 487
Transition Bonds issued by ACE Funding (c)	341	—	341	—
Long-term project funding	13	—	—	13
	$5,358	$ —	$ 4,858	$ 500

(a) Certain debt instruments that were categorized as level 1 at December 31, 2012, have been reclassified as level 2 to conform to the current period presentation.
(b) The carrying amount for Long-term debt is $4,177 million as of December 31, 2012.
(c) The carrying amount for Transition Bonds issued by ACE Funding, including amounts due within one year, is $295 million as of December 31, 2012.

The carrying amounts of all other financial instruments in the accompanying consolidated financial statements approximate fair value.

(14) COMMITMENTS AND CONTINGENCIES

General Litigation and Other Matters

In September 2011, an asbestos complaint was filed in the New Jersey Superior Court, Law Division, against ACE (among other defendants) asserting claims under New Jersey's Wrongful Death and Survival statutes. The complaint, filed by the estate of a decedent who was the wife of a former employee of ACE, alleges that the decedent's mesothelioma was caused by exposure to asbestos brought home by her husband on his work clothes. New Jersey courts have recognized a cause of action against a premise owner in a so-called "take home" case if it can be shown that the harm was foreseeable. In this case, the complaint seeks recovery of an unspecified amount of damages for, among other things, the decedent's past medical expenses, loss of earnings, and pain and suffering between the time of injury and death, and asserts a punitive damage claim. At this time, ACE has concluded that a loss is reasonably possible with respect to this matter, but ACE was unable to estimate an amount or range of reasonably possible loss because the damages sought are indeterminate and the matter involves facts that ACE believes are distinguishable from the facts of the "take-home" cause of action recognized by the New Jersey courts. This case remains pending.

In October 2010, a farm combine came into and remained in contact with a primary electric line in ACE's service territory in New Jersey. As a result, two individuals operating the combine received fatal electrical contact injuries. While attempting to rescue those two individuals, another individual sustained third-degree burns to his torso and upper extremities. In September 2012, the individual who received third-degree burns filed suit in New Jersey Superior Court, Salem County. In October 2012, an additional suit was filed in the same court by the estate of one of the deceased individuals. Plaintiffs in both cases allege that ACE was negligent in the design, construction, erection, operation and maintenance of its poles, power lines, and equipment, and that ACE failed to warn and protect the public from the foreseeable dangers of farm equipment contacting electric lines. ACE is investigating the incident involved and discovery is ongoing. At this time, ACE has concluded that a loss is reasonably possible with respect to these claims, but ACE is unable to estimate an amount or range of reasonably possible loss because the damages sought are indeterminate and the matter remains under investigation.

During 2012, Pepco Energy Services received letters on behalf of two school districts in Maryland, which claim that invoices in connection with electricity supply contracts contained certain allegedly unauthorized charges, totaling approximately $7 million. The school districts also claim additional compounded interest totaling approximately $9 million. Although no litigation involving Pepco Energy Services related to these claims has commenced, in August and September 2013, Pepco Energy Services received correspondence from the Superintendent of each of the school districts advising of the intention to render a decision regarding an unresolved dispute between the school district and Pepco Energy Services. Pepco Energy Services is reviewing the authority of the respective Superintendents to render decisions on the claims and it disputes the merits of the allegations regarding unauthorized charges as well as the claims of entitlement to compounded interest. As of September 30, 2013, the amount of loss, if any, that may be associated with these claims is not reasonably estimable, and Pepco Energy Services cannot estimate an amount or range of reasonably possible loss, if any, associated with the claims.

Environmental Matters

PHI, through its subsidiaries, is subject to regulation by various federal, regional, state and local authorities with respect to the environmental effects of its operations, including air and water quality control, solid and hazardous waste disposal and limitations on land use. Although penalties assessed for violations of environmental laws and regulations are not recoverable from customers of PHI's utility subsidiaries, environmental clean-up costs incurred by Pepco, DPL and ACE generally are included by each company in its respective cost of service for ratemaking purposes. The total accrued liabilities for the environmental contingencies described below of PHI and its subsidiaries at September 30, 2013 are summarized as follows:

	Transmission and Distribution	Legacy Generation: Regulated	Legacy Generation: Non-Regulated	Other	Total
	(millions of dollars)				
Beginning balance as of January 1	$ 15	$ 7	$ 5	$ 2	$ 29
Accruals	4	—	—	1	5
Payments	1	1	—	2	4
Ending balance as of September 30	18	6	5	1	30
Less amounts in Other Current Liabilities	3	1	—	—	4
Amounts in Other deferred credits	$ 15	$ 5	$ 5	$ 1	$ 26

Conectiv Energy Wholesale Power Generation Sites

In July 2010, PHI sold the Conectiv Energy wholesale power generation business to Calpine Corporation (Calpine). Under New Jersey's Industrial Site Recovery Act (ISRA), the transfer of ownership triggered an obligation on the part of Conectiv Energy to remediate any environmental contamination at each of the nine Conectiv Energy generating facility sites located in New Jersey. Under the terms of the sale, Calpine has assumed responsibility for performing the ISRA-required remediation and for the payment of all related ISRA compliance costs up to $10 million. PHI is obligated to indemnify Calpine for any ISRA compliance remediation costs in excess of $10 million. According to preliminary estimates, the costs of ISRA-required remediation activities at the nine generating facility sites located in New Jersey are in the range of approximately $7 million to $18 million. The amount accrued by PHI for the ISRA-required remediation activities at the nine generating facility sites is included in the table above in the column entitled "Legacy Generation – Non-Regulated."

In September 2011, PHI received a request for data from the U.S. Environmental Protection Agency (EPA) regarding operations at the Deepwater generating facility in New Jersey (which was included in the sale to Calpine) between February 2004 and July 1, 2010, to demonstrate compliance with the Clean Air Act's new source review permitting program. PHI responded to the data request. Under the terms of the Calpine sale, PHI is obligated to indemnify Calpine for any failure of PHI, on or prior to the closing date of the sale, to comply with environmental laws attributable to the construction of new, or modification of existing, sources of air emissions. At this time, PHI does not expect this inquiry to have a material adverse effect on its consolidated financial condition, results of operations or cash flows.

Franklin Slag Pile Site

In November 2008, ACE received a general notice letter from EPA concerning the Franklin Slag Pile site in Philadelphia, Pennsylvania, asserting that ACE is a potentially responsible party (PRP) that may have liability for clean-up costs with respect to the site and for the costs of implementing an EPA-mandated remedy. EPA's claims are based on ACE's sale of boiler slag from the B.L. England generating facility, then owned by ACE, to MDC Industries, Inc. (MDC) during the period June 1978 to May 1983. EPA claims that the boiler slag ACE sold to MDC contained copper and lead, which are hazardous substances under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA), and that the sales transactions may have constituted an arrangement for the disposal or treatment of hazardous substances at the site, which could be a basis for liability under CERCLA. The EPA letter also states that, as of the date of the letter, EPA's expenditures for response measures at the site have exceeded $6 million. EPA's feasibility study for this site conducted in 2007 identified a range of alternatives for permanent remedial measures with varying cost estimates, and the estimated cost of EPA's preferred alternative is approximately $6 million.

ACE believes that the B.L. England boiler slag sold to MDC was a valuable material with various industrial applications and, therefore, the sale was not an arrangement for the disposal or treatment of any hazardous substances as would be necessary to constitute a basis for liability under CERCLA. ACE intends to contest any claims to the contrary made by EPA. In a May 2009 decision arising under CERCLA, which did not involve ACE, the U.S. Supreme Court rejected an EPA argument that the sale of a useful product constituted an arrangement for disposal or treatment of hazardous substances. While this decision supports ACE's position, at this time ACE cannot predict how EPA will proceed with respect to the Franklin Slag Pile site, or what portion, if any, of the Franklin Slag Pile site response costs EPA would seek to recover from ACE. Costs to resolve this matter are not expected to be material and are expensed as incurred.

Peck Iron and Metal Site

EPA informed Pepco in a May 2009 letter that Pepco may be a PRP under CERCLA with respect to the cleanup of the Peck Iron and Metal site in Portsmouth, Virginia, and for costs EPA has incurred in cleaning up the site. The EPA letter states that Peck Iron and Metal purchased, processed, stored and shipped metal scrap from military bases, governmental agencies and businesses and that Peck's metal scrap operations resulted in the improper storage and disposal of hazardous substances. EPA bases its allegation that Pepco arranged for disposal or treatment of hazardous substances sent to the site on information provided by former Peck Iron and Metal personnel, who informed EPA that Pepco was a customer at the site. Pepco has advised EPA by letter that its records show no evidence of any sale of scrap metal by Pepco to the site. Even if EPA has such records and such sales did occur, Pepco believes that any such scrap metal sales may be entitled to the recyclable material exemption from CERCLA liability. In a Federal Register notice published on November 4, 2009, EPA placed the Peck Iron and Metal site on the National Priorities List. The National Priorities List, among other things, serves as a guide to EPA in determining which sites warrant further investigation to assess the nature and extent of the human health and environmental risks associated with a site. In September 2011, EPA initiated a remedial investigation/feasibility study (RI/FS) using federal funds. Pepco cannot at this time estimate an amount or range of reasonably possible loss associated with the RI/FS, any remediation activities to be performed at the site or any other costs that EPA might seek to impose on Pepco.

Ward Transformer Site

In April 2009, a group of PRPs with respect to the Ward Transformer site in Raleigh, North Carolina, filed a complaint in the U.S. District Court for the Eastern District of North Carolina, alleging cost recovery and/or contribution claims against a number of entities, including ACE, DPL and Pepco, based on their alleged sale of transformers to Ward Transformer, with respect to past and future response costs incurred by the PRP group in performing a removal action at the site. In a March 2010 order, the court denied the defendants' motion to dismiss. The litigation is moving forward with certain "test case" defendants (not including ACE, DPL and Pepco) filing summary judgment motions regarding liability. The case has been stayed as to the remaining defendants pending rulings upon the test cases. In a January 31, 2013 order, the district court granted summary judgment for the test case defendant whom plaintiffs alleged was liable based on its sale of transformers to Ward Transformer. The district court's order, which plaintiffs have appealed to the U.S. Court of Appeals for the Fourth Circuit, addresses only the liability of the test case defendant. PHI has concluded that a loss is reasonably possible with respect to this matter, but PHI was unable to estimate an amount or range of reasonably possible losses to which it may be exposed. PHI does not believe that any of its three utility subsidiaries had extensive business transactions, if any, with the Ward Transformer site.

Benning Road Site

In September 2010, PHI received a letter from EPA identifying the Benning Road location, consisting of a generation facility operated by Pepco Energy Services until the facility was deactivated in June 2012, and a transmission and distribution facility operated by Pepco, as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. The letter stated that the principal contaminants of concern are polychlorinated biphenyls and polycyclic aromatic hydrocarbons. In December 2011, the U.S. District Court for the District of Columbia approved a consent decree entered into by Pepco and Pepco Energy Services with the District of Columbia Department of the Environment (DDOE), which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10-15 acre portion of the adjacent Anacostia River. The RI/FS will form the basis for DDOE's selection of a remedial action for the Benning Road site and for the Anacostia River sediment associated with the site. The consent decree does not obligate Pepco or Pepco Energy Services to pay for or perform any remediation work, but it is anticipated that DDOE will look to the companies to assume responsibility for cleanup of any conditions in the river that are determined to be attributable to past activities at the Benning Road site.

In December 2012, DDOE approved the RI/FS work plan. RI/FS field work commenced in January 2013 and is still in progress. The final permit to authorize sampling in the river was issued in September 2013, and that sampling work is expected to be completed during the fourth quarter of 2013. In October 2013, Pepco and Pepco Energy Services submitted a work plan addendum for approval by DDOE identifying the location of groundwater monitoring wells to be installed at the site and sampled as the last phase of the field work. Following the field work, Pepco and Pepco Energy Services will prepare RI/ FS reports for review and approval by DDOE after solicitation and consideration of public comment. The next status report to the court is due on May 24, 2014.

The remediation costs accrued for this matter are included in the table above in the columns entitled "Transmission and Distribution," "Legacy Generation – Regulated," and "Legacy Generation – Non-Regulated."

Indian River Oil Release

In 2001, DPL entered into a consent agreement with the Delaware Department of Natural Resources and Environmental Control for remediation, site restoration, natural resource damage compensatory projects and other costs associated with environmental contamination resulting from an oil release at the Indian River generating facility, which was sold in June 2001. The amount of remediation costs accrued for this matter is included in the table above in the column entitled "Legacy Generation – Regulated."

Potomac River Mineral Oil Release

In January 2011, a coupling failure on a transformer cooler pipe resulted in a release of non-toxic mineral oil at Pepco's Potomac River substation in Alexandria, Virginia. An overflow of an underground secondary containment reservoir resulted in approximately 4,500 gallons of mineral oil flowing into the Potomac River.

Beginning in March 2011, DDOE issued a series of compliance directives requiring Pepco to prepare an incident report, provide certain records, and prepare and implement plans for sampling surface water and river sediments and assessing ecological risks and natural resources damages. Pepco completed field sampling during the fourth quarter of 2011 and submitted sampling results to DDOE during the second quarter of 2012. Pepco is continuing discussions with DDOE regarding the need for any further response actions but expects that additional monitoring of shoreline sediments may be required.

In June 2012, Pepco commenced discussions with DDOE regarding a possible consent decree that would resolve DDOE's threatened enforcement action, including civil penalties, for alleged violation of the District's Water Pollution Control Law, as well as for damages to natural resources. Pepco and DDOE have reached an agreement in principle that would consist of a combination of a civil penalty and Supplemental Environmental Projects (SEPs) with a total cost to Pepco of approximately $1 million. DDOE has endorsed Pepco's proposed SEP involving the installation and operation of a trash collection system at a stormwater outfall that drains to the Anacostia River. DDOE and Pepco will negotiate a consent decree to document the settlement of DDOE's enforcement action. Discussions will proceed separately with DDOE and the federal resource trustees regarding the settlement of a natural resource damage (NRD) claim under federal law. Based on discussions to date, PHI and Pepco do not believe that the resolution of DDOE's enforcement action or the federal NRD claim will have a material adverse effect on their respective financial condition, results of operations or cash flows.

As a result of the oil release, Pepco implemented certain interim operational changes to the secondary containment systems at the facility which involve pumping accumulated storm water to an aboveground holding tank for off-site disposal. In December 2011, Pepco completed the installation of a treatment system designed to allow automatic discharge of accumulated storm water from the secondary containment system. Pepco currently is seeking DDOE's and EPA's approval to commence operation of the new system on a pilot basis to demonstrate its effectiveness in meeting both secondary containment requirements and water quality standards related to the discharge of storm water from the facility. In the meantime, Pepco is continuing to use the aboveground holding tank to manage storm water from the secondary containment system.

The amount accrued for this matter is included in the table above in the column entitled "Transmission and Distribution."

Metal Bank Site

In January 2013, the National Oceanic and Atmospheric Administration (NOAA) contacted Pepco (and contacted DPL in March 2013) on behalf of itself and other federal and state trustees to request that Pepco and DPL execute a tolling agreement to facilitate settlement negotiations concerning natural resource damages allegedly caused by releases of hazardous substances, including polychlorinated biphenyls, at the Metal Bank Superfund Site located in Philadelphia, Pennsylvania. Pepco and DPL have executed the tolling agreement and will participate in settlement discussions with the NOAA, the trustees and other PRPs.

The amount accrued for this matter is included in the table above in the column entitled "Transmission and Distribution."

Brandywine Fly Ash Disposal Site

In February 2013, Pepco received a letter from the Maryland Department of the Environment (MDE) requesting that Pepco investigate the extent of waste on a Pepco right-of-way that traverses the Brandywine fly ash disposal site in Brandywine, Prince George's County, Maryland, owned by GenOn MD Ash

Management, LLC (GenOn). The letter requests that Pepco submit a plan of action for the investigation and capping of the right-of-way within 90 days. In its February 2013 response, Pepco informed MDE that, under a 2000 asset purchase and sale agreement (the Sale Agreement), the buyer of Pepco's generation assets assumed environmental liability for hazardous substances, including ash, which remain on or have been removed from the land on which the generating stations are situated. In July 2013, Pepco received a letter from the Maryland Attorney General's office on behalf of MDE, which takes the position that agreements between private parties do not operate to shift responsibility for compliance with landfill closure regulations and that Pepco, as the former owner and operator of a portion of the landfill, is responsible for compliance with closure requirements for that portion. The letter urges Pepco to work with GenOn concerning a closure plan and cap for the entire landfill and indicates that, absent an agreement between Pepco and GenOn concerning a closure plan and cap for the entire landfill or Pepco's submission of a plan to investigate and cap the portion of the landfill that Pepco owns, MDE will take formal action against Pepco to enforce the landfill closure regulations. In its July 22, 2013 response to the Maryland Attorney General's office, Pepco indicated, while reserving its rights under the Sale Agreement, its willingness to investigate the extent of, and propose an appropriate closure plan to address, ash on the right-of-way. Pepco submitted a schedule for development of a closure plan to MDE on September 30, 2013, which was approved on October 18, 2013.

PHI and Pepco have determined that a loss associated with this matter for PHI and Pepco is probable and have estimated that the costs for implementation of a closure plan and cap on the site are in the range of approximately $3 million to $6 million. PHI and Pepco believe that the costs incurred in this matter will be recoverable from GenOn under the Sale Agreement.

The amount accrued for this matter is included in the table above in the column entitled "Transmission and Distribution."

Watts Branch Insulating Fluid Release

On September 13, 2013, a Washington Metropolitan Area Transit Authority (WMATA) contractor damaged a Pepco underground transmission feeder while drilling a grout column for a subway tunnel under a city street. The damage caused the release of approximately 11,250 gallons of insulating fluid, a small amount of which reached the Watts Branch, a tributary of the Anacostia River. Pepco responded to the release of the insulating fluid. The U.S. Coast Guard (USCG) issued a notice of federal interest for an oil pollution incident, informing Pepco of its responsibility under the Oil Pollution Act of 1990 for removal costs and damages from the release and indicating that USCG would take Pepco's response actions into account in determining the penalty that may be assessed as a result of the release. In addition, on September 25, 2013, DDOE issued a compliance directive that requires Pepco to prepare an incident investigation report describing the events leading up to the release. The compliance directive also requires Pepco to prepare work plans for sampling the insulating fluid and for developing and implementing a biological assessment and physical habitat quality assessment to be conducted in Watts Branch. Pepco prepared the incident investigation report and work plans and submitted them to DDOE and USCG.

PHI and Pepco believe that a loss in this matter is probable; however, the costs to resolve this matter are expected to be less than $1 million and are being expensed as incurred. PHI and Pepco further believe that the costs incurred will be recoverable from the party or parties responsible for the release.

PHI's Cross-Border Energy Lease Investments

As discussed in Note (16), "Discontinued Operations – Cross-Border Energy Lease Investments," PHI held a portfolio of cross-border energy lease investments involving public utility assets located outside of the United States. Each of these investments was comprised of multiple leases and was structured as a sale and leaseback transaction commonly referred to by the IRS as a sale-in, lease-out, or SILO, transaction.

Since 2005, PHI's cross-border energy lease investments have been under examination by the IRS as part of the PHI federal income tax audits. In connection with the audit of PHI's 2001-2002 income tax returns, the

IRS disallowed the depreciation and interest deductions in excess of rental income claimed by PHI for six of the eight lease investments and, in connection with the audits of PHI's 2003-2005 and 2006-2008 income tax returns, the IRS disallowed such deductions in excess of rental income for all eight of the lease investments. In addition, the IRS has sought to recharacterize each of the leases as a loan transaction in each of the years under audit as to which PHI would be subject to original issue discount income. PHI has disagreed with the IRS' proposed adjustments to the 2001-2008 income tax returns and has filed protests of these findings for each year with the Office of Appeals of the IRS. In November 2010, PHI entered into a settlement agreement with the IRS for the 2001 and 2002 tax years for the purpose of commencing litigation associated with this matter and subsequently filed refund claims in July 2011 for the disallowed tax deductions relating to the leases for these years. In January 2011, as part of this settlement, PHI paid $74 million of additional tax for 2001 and 2002, penalties of $1 million, and $28 million in interest associated with the disallowed deductions. Since the July 2011 refund claims were not approved by the IRS within the statutory six-month period, in January 2012 PHI filed complaints in the U.S. Court of Federal Claims seeking recovery of the tax payment, interest and penalties. The 2003-2005 and 2006-2011 income tax return audits continue to be in process with the IRS Office of Appeals and the IRS Exam Division, respectively, and are not presently a part of the U.S. Court of Federal Claims litigation discussed above.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which PHI is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. While PHI believes that its tax position with regard to its cross-border energy lease investments is appropriate, after analyzing the recent U.S. Court of Appeals ruling, PHI determined in the first quarter of 2013 that its tax position with respect to the tax benefits associated with the cross-border energy leases no longer met the more-likely-than-not standard of recognition for accounting purposes. Accordingly, PHI recorded a non-cash charge of $377 million (after-tax) in the first quarter of 2013 (as discussed in Note (16), "Discontinued Operations – Cross-Border Energy Lease Investments"), consisting of a charge to reduce the carrying value of the cross-border energy lease investments and a charge to reflect the anticipated additional interest expense related to changes in PHI's estimated federal and state income tax obligations for the period over which the tax benefits ultimately may be disallowed. PHI had also previously made certain business assumptions regarding foreign investment opportunities available at the end of the full lease terms. During the first quarter of 2013, management believed that its conclusions regarding these business assumptions were no longer supportable, and the tax effects of this change in conclusion were included in the charge. While the IRS could require PHI to pay a penalty of up to 20% of the amount of additional taxes due, PHI believes that it is more likely than not that no such penalty will be incurred, and therefore no amount for any potential penalty was included in the charge recorded in the first quarter of 2013.

In the event that the IRS were to be successful in disallowing 100% of the tax benefits associated with these lease investments and recharacterizing these lease investments as loans, PHI estimated that, as of March 31, 2013, it would have been obligated to pay approximately $192 million in additional federal taxes (net of the $74 million tax payment described above) and approximately $50 million of interest on the additional federal taxes. These amounts, totaling $242 million, were estimated after consideration of certain tax benefits arising from matters unrelated to the leases that would offset the taxes and interest due, including PHI's best estimate of the expected resolution of other uncertain and effectively settled tax positions, the carrying back and carrying forward of any existing net operating losses, and the application of certain amounts paid in advance to the IRS. In order to mitigate PHI's ongoing interest costs associated with the $242 million estimate of additional taxes and interest, PHI made an advanced payment to the IRS of $242 million in the first quarter of 2013. This advanced payment was funded from currently available sources of liquidity and short-term borrowings. A portion of the proceeds from lease terminations was used to repay the short-term borrowings utilized to fund the advanced payment.

PHI continues to weigh its options with respect to its litigation with the IRS. Pursuant to an order issued by the judge on October 31, 2013, further discovery in the case is stayed until January 30, 2014.

Third Party Guarantees, Indemnifications, and Off-Balance Sheet Arrangements

PHI and certain of its subsidiaries have various financial and performance guarantees and indemnification obligations that they have entered into in the normal course of business to facilitate commercial transactions with third parties as discussed below.

As of September 30, 2013, PHI and its subsidiaries were parties to a variety of agreements pursuant to which they were guarantors for standby letters of credit, energy procurement obligations, and other commitments and obligations. The commitments and obligations, in millions of dollars, were as follows:

	Guarantor				
	PHI	Pepco	DPL	ACE	Total
	(millions of dollars)				
Energy procurement obligations of Pepco Energy Services (a)	$48	$—	$—	$—	$ 48
Guarantees associated with disposal of Conectiv Energy assets (b)	13	—	—	—	13
Guaranteed lease residual values (c)	3	5	7	4	19
Total	$64	$ 5	$ 7	$ 4	$ 80

(a) PHI has continued contractual commitments for performance and related payments of Pepco Energy Services primarily to Independent System Operators and distribution companies.
(b) Represents guarantees by PHI of Conectiv Energy's derivatives portfolio transferred in connection with the disposition of Conectiv Energy's wholesale business. The derivative portfolio guarantee is currently $13 million and covers Conectiv Energy's performance prior to the assignment. This guarantee will remain in effect until the end of 2015.
(c) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $56 million, $10 million of which is a guaranty by PHI, $15 million by Pepco, $18 million by DPL and $13 million by ACE. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

PHI and certain of its subsidiaries have entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties. These indemnification agreements typically cover environmental, tax, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements. Typically, claims may be made by third parties under these indemnification agreements over various periods of time depending on the nature of the claim. The maximum potential exposure under these indemnification agreements can range from a specified dollar amount to an unlimited amount depending on the nature of the claim and the particular transaction. The total maximum potential amount of future payments under these indemnification agreements is not estimable due to several factors, including uncertainty as to whether or when claims may be made under these indemnities.

Energy Services Performance Contracts

Pepco Energy Services has a diverse portfolio of energy savings services performance contracts that are associated with the installation of energy savings equipment or combined heat and power facilities for federal, state and local government customers. As part of the energy savings contracts, Pepco Energy Services typically guarantees that the equipment or systems it installs will generate a specified amount of energy savings on an annual basis over a multi-year period. As of September 30, 2013, the remaining notional amount of Pepco Energy Services' energy savings guarantees over the life of the multi-year performance contracts on: i) completed projects was $242 million with the longest guarantee having a remaining term of 14 years; and, ii) projects under construction was $194 million with the longest guarantee having a term of 23 years after construction. On an annual basis, Pepco Energy Services undertakes a measurement and verification process to determine the amount of energy savings for the year and whether there is any shortfall in the annual energy savings compared to the guaranteed amount.

As of September 30, 2013, Pepco Energy Services had a performance guarantee contract associated with the production at a combined heat and power facility that is under construction totaling $15 million in notional value over 20 years.

Pepco Energy Services recognizes a liability for the value of the estimated energy savings or production shortfalls when it is probable that the guaranteed amounts will not be achieved and the amount is reasonably estimable. As of September 30, 2013, Pepco Energy Services had an accrued liability of $1 million for its energy savings or combined heat and power performance contracts that it established during 2012. There was no significant change in the type of contracts issued during the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012.

Dividends

On October 24, 2013, Pepco Holdings' Board of Directors declared a dividend on common stock of 27 cents per share payable December 31, 2013, to stockholders of record on December 10, 2013.

(15) ACCUMULATED OTHER COMPREHENSIVE LOSS

The components of Pepco Holdings' AOCL relating to continuing operations are as follows. For additional information, see the consolidated statements of comprehensive income.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(millions of dollars)			
Balance, beginning of period	$ (41)	$ (36)	$ (42)	$ (34)
Treasury Lock				
Balance, beginning of period	(9)	(10)	(10)	(10)
Amount of net pre-tax loss reclassified to income:				
Interest expense	—	1	1	1
Total net pre-tax loss reclassified to income	—	1	1	1
Income Tax expense	—	1	—	1
Net change during period	—	—	1	—
Balance, end of period	(9)	(10)	(9)	(10)
Pension and Other Postretirement Benefit Plans				
Balance, beginning of period	(32)	(26)	(32)	(24)
Amount of net pre-tax loss reclassified to (from) income:				
Other Operation and Maintenance expense	1	1	2	(4)
Total net pre-tax loss reclassified to (from) income	1	1	2	(4)
Income Tax expense (benefit)	—	1	1	(2)
Net change during period	1	—	1	(2)
Balance, end of period	(31)	(26)	(31)	(26)
Balance, end of period	$ (40)	$ (36)	$ (40)	$ (36)

(16) DISCONTINUED OPERATIONS

PHI's income (loss) from discontinued operations, net of income taxes, is comprised of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(millions of dollars)			
Cross-border energy lease investments	$ 7	$ 17	$ (327)	$ 33
Pepco Energy Services' retail electric and natural gas supply businesses	1	8	5	25
Income (loss) from discontinued operations, net of income taxes	$ 8	$ 25	$ (322)	$ 58

Cross-Border Energy Lease Investments

Between 1994 and 2002, PCI entered into cross-border energy lease investments consisting of hydroelectric generation facilities, coal-fired electric generation facilities and natural gas distribution networks located outside of the United States. Each of these lease investments was structured as a sale and leaseback transaction commonly referred to as a sale-in, lease-out, or SILO, transaction. As of September 30, 2013 and December 31, 2012, the lease portfolio consisted of zero investments and six investments, respectively, with a net investment value of zero and $1,237 million, respectively.

During the second and third quarters of 2013, PHI terminated early all of its interests in the six remaining lease investments. PHI received aggregate net cash proceeds from these early terminations of $873 million (net of aggregate termination payments of $2.0 billion used to retire the non-recourse debt associated with the terminated leases) and recorded an aggregate pre-tax loss, including transaction costs, of approximately $3 million ($2 million after-tax), representing the excess of the carrying value of the terminated leases over the net cash proceeds received. As a result, PHI has reported the results of operations of the cross-border energy lease investments as discontinued operations in all periods presented in the accompanying consolidated statements of income (loss). Further, the assets and liabilities related to the cross-border energy lease investments are reported as held for disposition as of each date in the accompanying consolidated balance sheets.

Operating Results

The operating results for the cross-border energy lease investments are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(millions of dollars)			
Operating revenue from PHI's cross-border energy lease investments	$ —	$ 13	$ 7	$ 39
Non-cash charge to reduce carrying value of PHI's cross-border energy lease investments	—	—	(373)	—
Total operating revenue	$ —	$ 13	$ (366)	$ 39
Income (loss) from operations of discontinued operations, net of income taxes (a)	$ —	$ 8	$ (325)	$ 24
Net gains (losses) associated with the early termination of the cross-border energy lease investments, net of income taxes (b)	7	9	(2)	9
Income (loss) from discontinued operations, net of income taxes	$ 7	$ 17	$ (327)	$ 33

(a) Includes income tax expense (benefit) of approximately zero and $1 million for the three months ended September 30, 2013 and 2012, respectively, and approximately $(44) million and $3 million for the nine months ended September 30, 2013 and 2012, respectively.

(b) Includes income tax expense (benefit) of approximately $4 million and $30 million for the three months ended September 30, 2013 and 2012, respectively, and approximately $(1) million and $30 million for the nine months ended September 30, 2013 and 2012, respectively.

PHI is required to assess on a periodic basis the likely outcome of tax positions relating to its cross-border energy lease investments and, if there is a change or a projected change in the timing of the estimated tax benefits generated by the transactions, PHI is required to recalculate the value of its net investment.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which PHI is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. As a result of the court's ruling in this case, PHI determined in the first quarter of 2013 that its tax position with respect to the benefits associated with its cross-border energy leases no longer met the more-likely-than-not standard of recognition for accounting purposes, and PCI recorded after-tax non-cash charges of $323 million in the first quarter of 2013 and $6 million in the second quarter of 2013, consisting of the following components:

- A non-cash pre-tax charge of $373 million ($313 million after-tax) to reduce the carrying value of these cross-border energy lease investments under FASB guidance on leases (ASC 840). This pre-tax charge was originally recorded in the consolidated statement of income as a reduction in operating revenue and is now reflected in income (loss) from discontinued operations, net of income taxes.
- A non-cash charge of $16 million after-tax to reflect the anticipated additional net interest expense under FASB guidance for income taxes (ASC 740), related to estimated federal and state income tax obligations for the period over which the tax benefits may be disallowed. This after-tax charge was originally recorded in the consolidated statement of income as an increase in income tax expense and is now reflected in income (loss) from discontinued operations, net of income taxes. The after-tax interest charge for PHI on a consolidated basis was $70 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in the recognition of a $12 million interest benefit for the Power Delivery segment, and interest expense of $16 million for PCI and $66 million for Corporate and Other, respectively.

PHI had also previously made certain business assumptions regarding foreign investment opportunities available at the end of the full lease terms. In view of the change in PHI's tax position with respect to the tax benefits associated with the cross-border energy lease investments and PHI's resulting decision to pursue the early termination of these investments, management concluded in the first quarter of 2013 that these business assumptions were no longer supportable and the tax effects of this conclusion were reflected in the after-tax charge of $313 million described above.

PHI accrued no penalties associated with its re-assessment of the likely outcome of tax positions associated with the cross-border energy lease investments. While the IRS could require PHI to pay a penalty of up to 20% of the amount of additional taxes due, PHI believes that it is more likely than not that no such penalty will be incurred, and therefore no amount for any potential penalty was included in the charge.

For additional information concerning these cross-border energy lease investments, see Note (14), "Commitments and Contingencies – PHI's Cross-Border Energy Lease Investments."

<u>*Balance Sheet Information*</u>

As of September 30, 2013 and December 31, 2012, the assets held for disposition and liabilities associated with assets held for disposition related to the cross-border energy lease investments are:

	September 30, 2013	December 31, 2012
	(millions of dollars)	
Scheduled lease payments to PHI, net of non-recourse debt	$ —	$ 1,852
Less: Unearned and deferred income	—	(615)
Assets held for disposition	$ —	$ 1,237
Liabilities associated with assets held for disposition	$ 1	$ 1

To ensure credit quality, PHI regularly monitored the financial performance and condition of the lessees under the former cross-border energy lease investments. Changes in credit quality were assessed to determine whether they affected the carrying value of the leases. PHI compared each lessee's performance to annual compliance requirements set by the terms and conditions of the leases and compared published credit ratings to minimum credit rating requirements in the leases for lessees with public credit ratings. In addition, PHI routinely met with senior executives of the lessees to discuss their company and asset performance. If the annual compliance requirements or minimum credit ratings were not met, remedies would have been available under the leases.

The table below shows PHI's net investment in these leases by the published credit ratings of the lessees as of September 30, 2013 and December 31, 2012:

Lessee Rating (a)	September 30, 2013	December 31, 2012
	(millions of dollars)	
Rated Entities		
AA/Aa and above	$ —	$ 766
A	—	471
Total	$ —	$ 1,237

(a) Excludes the credit ratings associated with collateral posted by the lessees in these transactions.

Retail Electric and Natural Gas Supply Businesses of Pepco Energy Services

On March 21, 2013, Pepco Energy Services entered into an agreement whereby a third party assumed all the rights and obligations of the remaining natural gas supply customer contracts, and the associated supply obligations, inventory and derivative contracts. The transaction was completed on April 1, 2013. In addition, in the second quarter of 2013, Pepco Energy Services completed the wind-down of its retail electric supply business by terminating its remaining customer supply and wholesale purchase obligations beyond June 30, 2013. As a result, PHI has reported the results of operations of Pepco Energy Services' retail electric and natural gas supply businesses as discontinued operations in all periods presented in the accompanying consolidated statements of income (loss). Further, the assets and liabilities of Pepco Energy Services' retail electric and natural gas supply businesses are reported as held for disposition as of each date presented in the accompanying consolidated balance sheets.

Operating Results

The operating results for the retail electric and natural gas supply businesses of Pepco Energy Services are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
		(millions of dollars)		
Operating revenue	$ —	$ 76	$ 84	$ 346
Income from operations of discontinued operations, net of income taxes	$ 1	$ 8	$ 4	$ 25
Net gains associated with the accelerated disposition of retail electric and natural gas contracts, net of income taxes	—	—	1	—
Income from discontinued operations, net of income taxes (a)	$ 1	$ 8	$ 5	$ 25

(a) Includes income tax expense of approximately $1 million and $5 million for the three months ended September 30, 2013 and 2012, respectively, and approximately $3 million and $17 million for the nine months ended September 30, 2013 and 2012, respectively.

The net gains associated with the accelerated disposition of retail electric and natural gas contracts, net of income taxes, for the nine months ended September 30, 2013, reflects the pre-tax loss of $3 million ($2 million after-tax) associated with the terminations of the retail electric customer supply and wholesale purchase obligations and the pre-tax gain of $8 million ($5 million after-tax) recognized regarding the assumption by a third party, on April 1, 2013, of all the rights and obligations of the derivative contracts associated with the retail natural gas supply business. The net gain associated with the retail natural gas supply business was partially offset by unrealized derivative losses that were previously included in AOCL and were reclassified to income because PHI determined that the hedged forecasted purchases of supply for customers were probable not to occur. Accordingly, in the first quarter of 2013, PHI recognized $4 million of pre-tax unrealized derivative losses ($2 million after-tax) that previously were included in AOCL as cash flow hedges.

Balance Sheet Information

As of September 30, 2013 and December 31, 2012, the retail energy supply business of Pepco Energy Services had net accounts receivable of zero and $33 million, respectively, inventory assets of $2 million and $3 million, respectively, gross derivative assets of zero and $1 million, respectively, other current assets of zero and $1 million, respectively, accrued liabilities of $3 million and $20 million, respectively, gross derivative liabilities of zero and $21 million, respectively, exclusive of the collateral pledged by Pepco Energy Services against the derivative liabilities, and other current liabilities of zero and $1 million, respectively. The fair values of the derivative assets and liabilities were considered levels 1 and 2 within the fair value hierarchy.

Derivative Instruments and Hedging Activities

Derivatives were used by the retail electric and natural gas supply businesses of Pepco Energy Services to hedge commodity price risk.

The retail electric and natural gas supply businesses of Pepco Energy Services entered into energy commodity contracts in the form of natural gas futures, swaps, options and forward contracts to hedge commodity price risk in connection with the purchase of physical natural gas and electricity for distribution to customers. The primary risk management objective was to manage the spread between retail sales commitments and the cost of supply used to service those commitments to ensure stable cash flows and lock in favorable prices and margins when they became available. There were no derivatives for Pepco Energy Services as of September 30, 2013.

Commodity contracts held by the retail electric and natural gas supply businesses of Pepco Energy Services that were not designated for hedge accounting, did not qualify for hedge accounting, or did not meet the requirements for normal purchase and normal sale accounting, were marked to market through current earnings. Forward contracts that met the requirements for normal purchase and normal sale accounting were recorded on an accrual basis.

The table below identifies the balance sheet location and fair values of the retail electric and natural gas supply businesses' derivative instruments as of December 31, 2012:

Balance Sheet Caption	Derivatives Designated as Hedging Instruments (a)	Other Derivative Instruments	Gross Derivative Instruments	Effects of Cash Collateral and Netting	Net Derivative Instruments
	As of December 31, 2012 (millions of dollars)				
Assets held for disposition (current assets)	$ —	$ 1	$ 1	$ —	$ 1
Total Derivative assets	—	1	1	—	1
Liabilities associated with assets held for disposition (current liabilities)	(10)	(9)	(19)	16	(3)
Liabilities associated with assets held for disposition (non-current liabilities)	(1)	(1)	(2)	2	—
Total Derivative liabilities	(11)	(10)	(21)	18	(3)
Net Derivative (liability) asset	$ (11)	$ (9)	$ (20)	$ 18	$ (2)

(a) Amounts included in Derivatives Designated as Hedging Instruments primarily consist of derivatives that were designated as cash flow hedges prior to Pepco Energy Services' election to discontinue cash flow hedge accounting for these derivatives.

Under FASB guidance on the offsetting of balance sheet accounts (ASC 210-20), the retail electric and natural gas supply businesses of Pepco Energy Services offset the fair value amounts recognized for derivative instruments and the fair value amounts recognized for related collateral positions executed with the same counterparty under master netting agreements. No derivative assets or liabilities were available to be offset under master netting arrangements as of December 31, 2012. The amount of cash collateral that was offset against these derivative positions is as follows:

	December 31, 2012 (millions of dollars)
Cash collateral pledged to counterparties with the right to reclaim (a)	$ 18

(a) Includes cash deposits on commodity brokerage accounts.

As of December 31, 2012, all cash collateral pledged by the retail electric and natural gas supply businesses related to derivative instruments accounted for at fair value was entitled to be offset under master netting agreements.

Derivatives Designated as Hedging Instruments

As of December 31, 2012, the cumulative net pre-tax loss related to effective cash flow hedges of the retail electric and natural gas supply businesses of Pepco Energy Services included in AOCL was $10 million ($6 million after-tax). With the assumption by a third party, on April 1, 2013, of all the rights and obligations of the derivative contracts associated with the retail natural gas supply business, and the completion of the wind-down of the retail electric supply business in the second quarter of 2013, all of the losses deferred in AOCL associated with derivatives that Pepco Energy Services had previously designated as cash flow hedges were reclassified into income. As a result, losses of zero and $10 million ($6 million after-tax) were reclassified from AOCL to income for the three and nine months ended September 30, 2013, respectively. Losses of $6 million ($4 million after-tax) and $31 million ($18 million after-tax) were reclassified from AOCL to income for the three and nine months ended September 30, 2012, respectively. As of September 30, 2012, the cumulative net pre-tax loss related to effective cash flow hedges of the retail electric and natural gas supply businesses of Pepco Energy Services included in AOCL was $11 million (after-tax), of which $10 million (after-tax) was expected to be reclassified to income during the following twelve months.

Other Derivative Activity

The retail electric and natural gas supply businesses of Pepco Energy Services held certain derivatives that were not in hedge accounting relationships and were not designated as normal purchases or normal sales. These derivatives were recorded at fair value on the balance sheet with the gain or loss for changes in fair value recorded through income.

For the three and nine months ended September 30, 2013 and 2012, the amount of the pre-tax derivative gain (loss) for the retail electric and natural gas supply businesses of Pepco Energy Services recognized in income is provided in the table below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(millions of dollars)			
Reclassification of mark-to-market to realized on settlement of contracts	$ —	$ 5	$ 10	$ 22
Unrealized mark-to-market gain (loss)	—	3	—	(2)
Total net gain	$ —	$ 8	$ 10	$ 20

As of September 30, 2013, the retail electric and natural gas supply businesses of Pepco Energy Services had no outstanding commodity forward contracts or derivative positions.

As of December 31, 2012, the retail electric and natural gas supply businesses of Pepco Energy Services had the following net outstanding commodity forward contract quantities and net position on derivatives that did not qualify for hedge accounting:

	December 31, 2012	
Commodity	Quantity	Net Position
Natural gas (MMBtu)	2,867,500	Long
Financial transmission rights (MWh)	181,008	Long
Electricity (MWh)	261,240	Long

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	**2012**	**2013**	**2012**
	(millions of dollars)			
Operating Revenue	$ 605	$ 582	$ 1,551	$ 1,503
Operating Expenses				
Purchased energy	227	227	576	572
Other operation and maintenance	95	97	292	301
Depreciation and amortization	51	48	147	143
Other taxes	103	103	280	285
Total Operating Expenses	476	475	1,295	1,301
Operating Income	129	107	256	202
Other Income (Expenses)				
Interest expense	(28)	(27)	(82)	(76)
Other income	5	5	14	13
Total Other Expenses	(23)	(22)	(68)	(63)
Income Before Income Tax Expense	106	85	188	139
Income Tax Expense	40	35	62	38
Net Income	$ 66	$ 50	$ 126	$ 101

The accompanying Notes are an integral part of these Financial Statements.

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

	September 30, 2013	December 31, 2012
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 8	$ 9
Restricted cash equivalents	3	—
Accounts receivable, less allowance for uncollectible accounts of $15 million and $13 million, respectively	365	318
Inventories	72	69
Prepayments of income taxes	9	9
Income taxes receivable	101	31
Prepaid expenses and other	36	25
Total Current Assets	594	461
INVESTMENTS AND OTHER ASSETS		
Regulatory assets	536	487
Prepaid pension expense	337	353
Investment in trust	33	31
Income taxes receivable	35	102
Other	63	59
Total Investments and Other Assets	1,004	1,032
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	7,164	6,850
Accumulated depreciation	(2,730)	(2,705)
Net Property, Plant and Equipment	4,434	4,145
TOTAL ASSETS	$ 6,032	$ 5,638

The accompanying Notes are an integral part of these Financial Statements.

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

	September 30, 2013	December 31, 2012
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 32	$ 231
Current portion of long-term debt	375	200
Accounts payable and accrued liabilities	217	214
Accounts payable due to associated companies	31	41
Capital lease obligations due within one year	9	8
Taxes accrued	30	58
Interest accrued	39	17
Liabilities and accrued interest related to uncertain tax positions	25	—
Customer deposits	47	48
Other	59	58
Total Current Liabilities	864	875
DEFERRED CREDITS		
Regulatory liabilities	141	141
Deferred income tax liabilities, net	1,343	1,219
Investment tax credits	3	4
Other postretirement benefit obligations	68	66
Liabilities and accrued interest related to uncertain tax positions	10	53
Other	65	66
Total Deferred Credits	1,630	1,549
LONG-TERM LIABILITIES		
Long-term debt	1,575	1,501
Capital lease obligations	65	70
Total Long-Term Liabilities	1,640	1,571
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
EQUITY		
Common stock, $.01 par value, 200,000,000 shares authorized, 100 shares outstanding	—	—
Premium on stock and other capital contributions	930	755
Retained earnings	968	888
Total Equity	1,898	1,643
TOTAL LIABILITIES AND EQUITY	$ 6,032	$ 5,638

The accompanying Notes are an integral part of these Financial Statements.

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2013	2012
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 126	$ 101
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	147	143
Deferred income taxes	110	170
Changes in:		
Accounts receivable	(59)	(31)
Inventories	(3)	(21)
Prepaid expenses	(8)	5
Regulatory assets and liabilities, net	(74)	(67)
Accounts payable and accrued liabilities	3	29
Prepaid pension expense, excluding contributions	16	16
Pension contributions	—	(85)
Income tax-related prepayments, receivables and payables	(50)	(86)
Interest accrued	21	22
Other assets and liabilities	(2)	(6)
Net Cash From Operating Activities	227	190
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(403)	(449)
Department of Energy capital reimbursement awards received	16	23
Changes in restricted cash equivalents	(3)	—
Net other investing activities	(8)	(1)
Net Cash Used By Investing Activities	(398)	(427)
FINANCING ACTIVITIES		
Dividends paid to Parent	(46)	(35)
Capital contributions from Parent	175	50
Issuances of long-term debt	250	200
Reacquisitions of long-term debt	—	(38)
(Repayments) issuances of short-term debt, net	(200)	60
Cost of issuances	(4)	(4)
Net other financing activities	(5)	(3)
Net Cash From Financing Activities	170	230
Net Decrease in Cash and Cash Equivalents	(1)	(7)
Cash and Cash Equivalents at Beginning of Period	9	12
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 8	$ 5
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash received for income taxes (includes payments from PHI for federal income taxes)	$ (26)	$ (40)
Non-cash activities		
Reclassification of property, plant and equipment to regulatory assets	—	53
Reclassification of asset removal costs regulatory liability to accumulated depreciation	—	19

The accompanying Notes are an integral part of these Financial Statements.

POTOMAC ELECTRIC POWER COMPANY
STATEMENT OF EQUITY
(Unaudited)

(millions of dollars, except shares)	Common Stock Shares	Common Stock Par Value	Premium on Stock	Retained Earnings	Total
BALANCE, DECEMBER 31, 2012	100	$ —	$ 755	$ 888	$1,643
Net Income	—	—	—	23	23
Capital contribution from Parent	—	—	175	—	175
BALANCE, MARCH 31, 2013	100	—	930	911	1,841
Net Income	—	—	—	37	37
Dividends on common stock	—	—	—	(15)	(15)
BALANCE, JUNE 30, 2013	100	—	930	933	1,863
Net Income	—	—	—	66	66
Dividends on common stock	—	—	—	(31)	(31)
BALANCE, SEPTEMBER 30, 2013	100	$ —	$ 930	$ 968	$1,898

The accompanying Notes are an integral part of these Financial Statements.

NOTES TO FINANCIAL STATEMENTS

POTOMAC ELECTRIC POWER COMPANY

(1) ORGANIZATION

Potomac Electric Power Company (Pepco) is engaged in the transmission and distribution of electricity in the District of Columbia and major portions of Prince George's County and Montgomery County in suburban Maryland. Pepco also provides Default Electricity Supply, which is the supply of electricity at regulated rates to retail customers in its service territories who do not elect to purchase electricity from a competitive supplier. Default Electricity Supply is known as Standard Offer Service in both the District of Columbia and Maryland. Pepco is a wholly owned subsidiary of Pepco Holdings, Inc. (Pepco Holdings or PHI).

(2) SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation

Pepco's unaudited financial statements are prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). Pursuant to the rules and regulations of the Securities and Exchange Commission, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with GAAP have been omitted. Therefore, these financial statements should be read along with the annual financial statements included in Pepco's annual report on Form 10-K for the year ended December 31, 2012. In the opinion of Pepco's management, the unaudited financial statements contain all adjustments (which all are of a normal recurring nature) necessary to state fairly Pepco's financial condition as of September 30, 2013, in accordance with GAAP. The year-end December 31, 2012 balance sheet included herein was derived from audited financial statements, but does not include all disclosures required by GAAP. Interim results for the three and nine months ended September 30, 2013 may not be indicative of results that will be realized for the full year ending December 31, 2013.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities in the financial statements and accompanying notes. Although Pepco believes that its estimates and assumptions are reasonable, they are based upon information available to management at the time the estimates are made. Actual results may differ significantly from these estimates.

Significant matters that involve the use of estimates include the assessment of contingencies, future cash flows and fair value amounts for use in asset impairment evaluations, pension and other postretirement benefits assumptions, the assessment of the probability of recovery of regulatory assets, accrual of storm restoration costs, accrual of unbilled revenue, recognition of changes in network service transmission rates for prior service year costs, accrual of self-insurance reserves for general and auto liability claims, and income tax provisions and reserves. Additionally, Pepco is subject to legal, regulatory and other proceedings and claims that arise in the ordinary course of its business. Pepco records an estimated liability for these proceedings and claims when it is probable that a loss has been incurred and the loss is reasonably estimable.

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in Pepco's gross revenues were $91 million and $93 million for the three months ended September 30, 2013 and 2012, respectively, and $244 million and $250 million for the nine months ended September 30, 2013 and 2012, respectively.

Reclassifications and Adjustments

Certain prior period amounts have been reclassified in order to conform to the current period presentation.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

None.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Joint and Several Liability Arrangements (Accounting Standards Codification (ASC) 405)

In February 2013, the Financial Accounting Standards Board (FASB) issued new recognition and disclosure requirements for certain joint and several liability arrangements where the total amount of the obligation is fixed at the reporting date. For arrangements within the scope of this standard, Pepco will be required to include in its liabilities the additional amounts it expects to pay on behalf of its co-obligors, if any. Pepco will also be required to provide additional disclosures including the nature of the arrangements with its co-obligors, the total amounts outstanding under the arrangements between Pepco and its co-obligors, the carrying value of the liability, and the nature and limitations of any recourse provisions that would enable recovery from other entities.

The new requirements would be effective retroactively beginning on January 1, 2014, with implementation required for prior periods if joint and several liability arrangement obligations exist as of January 1, 2014. Pepco is evaluating the impact of this new guidance on its financial statements.

Income Taxes (ASC 740)

In July 2013, the FASB issued new guidance that will require the netting of certain unrecognized tax benefits against a deferred tax asset for a loss or other similar tax carryforward that would apply upon settlement of the uncertain tax position. The new requirements are effective prospectively beginning with Pepco's March 31, 2014 financial statements for all unrecognized tax benefits existing at the adoption date. Retrospective implementation and early adoption of the guidance are permitted. Pepco is evaluating the impact of this new guidance on its financial statements.

(5) SEGMENT INFORMATION

Pepco operates its business as one regulated utility segment, which includes all of its services as described above.

(6) REGULATORY MATTERS

Rate Proceedings

Over the last several years, Pepco has proposed in each of its jurisdictions the adoption of a mechanism to decouple retail distribution revenue from the amount of power delivered to retail customers. To date, a bill stabilization adjustment (BSA) was approved and implemented for electric service in Maryland and the District of Columbia. Under the BSA, customer distribution rates are subject to adjustment (through a credit or surcharge mechanism), depending on whether actual distribution revenue per customer exceeds or falls short of the revenue-per-customer amount approved by the applicable public service commission.

District of Columbia

Electric Distribution Base Rates

On March 8, 2013, Pepco filed an application with the District of Columbia Public Service Commission (DCPSC) to increase its annual electric distribution base rates by approximately $44.1 million (as adjusted by Pepco on September 16, 2013), based on a requested return on equity (ROE) of 10.25%. The requested rate increase is for the purpose of recovering (i) Pepco's expenses associated with ongoing efforts to maintain safe and reliable service for its customers, (ii) Pepco's investment in infrastructure to maintain and harden the electric distribution system, and (iii) Pepco's investment in major reliability enhancement improvements. Evidentiary hearings are expected to begin on November 4, 2013 and a final DCPSC decision is expected in the first quarter of 2014.

Maryland

Electric Distribution Base Rates

In December 2011, Pepco submitted an application with the Maryland Public Service Commission (MPSC) to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $68.4 million (subsequently reduced by Pepco to $66.2 million), based on a requested ROE of 10.75%. In July 2012, the MPSC issued an order approving an annual rate increase of approximately $18.1 million, based on an ROE of 9.31%. The order also reduced Pepco's depreciation rates, which lowered annual depreciation and amortization expenses by an estimated $27.3 million. The lower depreciation rates resulted from, among other things, the rebalancing of excess reserves for estimated future removal costs identified in a depreciation study conducted as part of the rate case filing. The identified excess reserves for estimated future removal costs, reported as regulatory liabilities, were reclassified to accumulated depreciation among various plant accounts. Among other things, the order also authorizes Pepco to recover the actual cost of advanced metering infrastructure (AMI) meters installed during the 2011 test year and states that cost recovery for AMI deployment will be allowed in future rate cases in which Pepco demonstrates that the system is cost effective. The new revenue rates and lower depreciation rates were effective on July 20, 2012. The Maryland Office of People's Counsel (OPC) has sought rehearing on the portion of the order allowing Pepco to recover the costs of AMI meters installed during the test year; that motion remains pending.

On November 30, 2012, Pepco submitted an application with the MPSC to increase its electric distribution base rates. The filing sought approval of an annual rate increase of approximately $60.8 million, based on a requested ROE of 10.25%. The requested rate increase was for the purpose of recovering reliability enhancements to serve Maryland customers. Pepco also proposed a three-year Grid Resiliency Charge rider for recovery of costs totaling approximately $192 million associated with its plan to accelerate investments in infrastructure in a condensed timeframe. Acceleration of resiliency improvements was one of several recommendations included in a September 2012 report from Maryland's Grid Resiliency Task Force (as discussed below under "Resiliency Task Forces"). Specific projects under Pepco's Grid Resiliency Charge plan included acceleration of its tree-trimming cycle, upgrade of 12 additional feeders per year for two years and undergrounding of six distribution feeders. In addition, Pepco proposed a reliability performance-based mechanism that would allow Pepco to earn up to $1 million as an incentive for meeting enhanced reliability goals in 2015, but provided for a credit to customers of up to $1 million in total if Pepco does not meet at least the minimum reliability performance targets. Pepco requested that any credits/charges would flow through the proposed Grid Resiliency Charge rider.

On July 12, 2013, the MPSC issued an order related to Pepco's November 30, 2012 application approving an annual rate increase of approximately $27.9 million, based on an ROE of 9.36%. The order provides for the full recovery of storm restoration costs incurred as a result of recent major storm events, including the derecho storm in June 2012 and Hurricane Sandy in October 2012, by including the related capital costs in the rate base and amortizing the related deferred operation and maintenance expenses of $23.6 million over a five-year period. The order excludes the cost of AMI meters from Pepco's rate base until such time as Pepco demonstrates the cost effectiveness of the AMI system; as a result, costs for AMI meters incurred with respect to the 2012 test year and beyond will be treated as other incremental AMI costs incurred in conjunction with the deployment of the AMI system that are deferred and on which a return is earned, but only until such cost effectiveness has been demonstrated and such costs are included in rates. However, the MPSC's July 2012 order in Pepco's previous electric distribution base rate case, which allowed Pepco to recover the costs of meters installed during the 2011 test year for that case, remains in effect, and the Maryland OPC's motion for rehearing in that case remains pending.

The order also approved a Grid Resiliency Charge for recovery of costs totaling approximately $24.0 million associated with Pepco's proposed plan to accelerate investments related to certain priority feeders, provided that Pepco provides additional information to the MPSC before implementing the surcharge related to performance objectives, milestones and costs, and makes annual filings with the MPSC thereafter concerning this project, which will permit the MPSC to establish the applicable Grid Resiliency Charge rider for each following year. The MPSC did not approve the proposed acceleration of the tree-trimming cycle or the undergrounding of six distribution feeders. The MPSC rejected Pepco's proposed reliability performance-based mechanism. The new rates were effective on July 12, 2013.

On July 26, 2013, Pepco filed a notice of appeal of this July 12, 2013 order in the Circuit Court for the City of Baltimore. Other parties have also filed notices of appeal in that court and in the Circuit Court for Montgomery County. The other parties' appeals have been transferred to the Circuit Court for the City of Baltimore and consolidated with Pepco's appeal. Pepco intends to file another electric distribution base rate case with the MPSC in the fourth quarter of 2013. Pepco is continuing to review the impact of the order and may also consider other actions to more closely align its spending in Maryland to the revenue received while maintaining compliance with the MPSC's established standards applicable to the utility.

MPSC New Generation Contract Requirement

In September 2009, the MPSC initiated an investigation into whether Maryland electric distribution companies (EDCs) should be required to enter into long-term contracts with entities that construct, acquire or lease, and operate, new electric generation facilities in Maryland.

In April 2012, the MPSC issued an order determining that there is a need for one new power plant in the range of 650 to 700 megawatts (MW) beginning in 2015. The order requires Pepco, its affiliate Delmarva Power & Light Company (DPL), and Baltimore Gas and Electric Company (BGE) (collectively, the Contract EDCs) to negotiate and enter into a contract with the winning bidder of a competitive bidding process in amounts proportional to their relative Standard Offer Service (SOS) loads. Under the contract, the winning bidder will construct a 661 MW natural gas-fired combined cycle generation plant in Waldorf, Maryland, with an expected commercial operation date of June 1, 2015. The order acknowledged the Contract EDCs' concerns about the requirements of the contract and directed them to negotiate with the winning bidder and submit any proposed changes in the contract to the MPSC for approval. The order further specified that the Contract EDCs will recover the associated costs through surcharges on their respective SOS customers.

In April 2012, a group of generating companies operating in the PJM Interconnection, LLC (PJM) region filed a complaint in the U.S. District Court for the District of Maryland challenging the MPSC's order on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. In May 2012, the Contract EDCs and other parties filed notices of appeal in circuit courts in Maryland requesting judicial review of the MPSC's order. These circuit court appeals were consolidated in the Circuit Court for Baltimore City.

On April 16, 2013, the MPSC issued an order approving a final form of the contract and directing the Contract EDCs to enter into the contract with the winning bidder in amounts proportional to their relative SOS loads. On June 4, 2013, Pepco entered into the contract in accordance with the terms of the MPSC's order; however, under the contract's own terms, it will not become effective, if at all, until all legal proceedings related to the contract and the actions of the MPSC in the related proceeding have been resolved.

On September 30, 2013, the U.S. District Court for the District of Maryland issued a ruling that the MPSC's April 2012 order violated the Supremacy Clause of the U.S. Constitution by attempting to regulate wholesale prices. In contrast, on October 1, 2013, the Maryland Circuit Court for Baltimore City upheld the MPSC's orders requiring the Contract EDCs to enter into the contracts.

On October 24, 2013, the Federal district court issued an order ruling that the contracts are illegal and unenforceable. This Federal district court order and its associated ruling could impact the state circuit court appeal, to which the Contract EDCs are parties, although such impact, if any, cannot be determined at this time. PHI expects the Federal district court decision to be appealed. The Contract EDCs also will likely appeal the state court decision to the Maryland Court of Special Appeals.

Assuming the contract, as currently written, were to become effective by the expected commercial operation date of June 1, 2015, Pepco continues to believe that it may be required to account for its proportional share of the contract as a derivative instrument at fair value with an offsetting regulatory asset because it would recover any payments under the contract from SOS customers. In such event, Pepco estimates it would be required to record an aggregate derivative liability ranging from $40 million to $50 million, with an offsetting regulatory asset in a like amount. The estimated range and the related assumptions may change prior to the time that the contract becomes effective, if at all. Pepco has concluded that any accounting for this contract would not be required until all legal proceedings related to this contract and the actions of the MPSC in the related proceeding have been resolved.

Pepco is evaluating these proceedings to determine (i) the extent of the negative effect that the contract for new generation may have on its credit metrics, as calculated by independent rating agencies that evaluate and rate Pepco and its debt issuances, (ii) the effect on Pepco’s ability to recover its associated costs of the contract for new generation if a significant number of SOS customers elect to buy their energy from alternative energy suppliers, and (iii) the effect of the contract on the financial condition, results of operations and cash flows of Pepco.

Resiliency Task Forces

In July 2012, the Maryland governor signed an Executive Order directing his energy advisor, in collaboration with certain state agencies, to solicit input and recommendations from experts on how to improve the resiliency and reliability of the electric distribution system in Maryland. The resulting Grid Resiliency Task Force issued its report in September 2012, in which it made 11 recommendations. The governor forwarded the report to the MPSC in October 2012, urging the MPSC to quickly implement the first four recommendations: (i) strengthen existing reliability and storm restoration regulations; (ii) accelerate the investment necessary to meet the enhanced metrics; (iii) allow surcharge recovery for the accelerated investment; and (iv) implement clearly defined performance metrics into the traditional ratemaking scheme. Pepco’s electric distribution base rate case filed with the MPSC on November 30, 2012 attempted to address the Grid Resiliency Task Force recommendations. In July, the MPSC issued an order in the Pepco Maryland electric distribution base rate case that only partially approved the proposed Grid Resiliency Charge. See “Rate Proceedings – Maryland – Electric Distribution Base Rates” above for more information about this base rate case.

In August 2012, the District of Columbia mayor issued an Executive Order establishing the Mayor’s Power Line Undergrounding Task Force (the DC Undergrounding Task Force). The stated purpose of the DC Undergrounding Task Force was to pool the collective resources available in the District of Columbia to produce an analysis of the technical feasibility, infrastructure options and reliability implications of undergrounding new or existing overhead distribution facilities in the District of Columbia. These resources included legislative bodies, regulators, utility personnel, experts and other parties who could contribute in a meaningful way to the DC Undergrounding Task Force. The options that are available for financing these efforts were also to be evaluated to identify required legislative or regulatory actions to implement these recommendations. On May 13, 2013, the DC Undergrounding Task Force issued a written recommendation endorsing a $1 billion plan of the DC Undergrounding Task Force to bury 60 of the District of Columbia’s most outage-prone power lines. Under this recommendation, (i) Pepco would fund approximately $500 million of the $1 billion estimated cost to complete this project, recovering those costs through surcharges on the electric bills of Pepco District of Columbia customers; (ii) $375 million of the undergrounding project cost would be financed by the District of Columbia's issuance of securitized bonds, which bonds would be repaid through surcharges on the electric bills of Pepco District of Columbia customers (Pepco would not earn a return on the underground lines paid for with the proceeds received from the issuance of the bonds, but those lines would be transferred to Pepco to operate and maintain); and (iii) the remaining amount would be funded through the District of Columbia Department of Transportation's existing capital projects program. Legislation providing for implementation of the report's recommendation was introduced in the Council of the District of Columbia on July 10, 2013. This legislation is expected to be voted upon by the City Council during the fourth quarter of 2013. Once the bill is passed by the City Council, it requires approval of the District of Columbia Mayor and a 30-day Congressional review period before becoming law, which is expected to occur in the first quarter of 2014. The final step would be DCPSC approval of the underground project plan and a DCPSC order approving the financing orders required by the legislation that establishes the customer surcharges to recover Pepco's portion of the undergrounding costs and the repayment of the District of Columbia's securitized bonds, a decision on which is expected during the third quarter of 2014.

MAPP Project

On August 24, 2012, the board of PJM terminated the Mid-Atlantic Power Pathway (MAPP) project and removed it from PJM's regional transmission expansion plan. PHI had been directed to construct the MAPP project, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region's transmission system. In December 2012, Pepco submitted a filing to the Federal Energy Regulatory Commission (FERC) seeking recovery of $50 million of abandoned MAPP costs over a five-year recovery period. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

Various protests were submitted in response to Pepco's December 2012 filing, arguing, among other things, that FERC should disallow a portion of the rate of return involving an incentive adder that would be applied to the abandoned costs, and requesting a hearing on various issues such as the amount of the ROE and the prudence of the costs. On February 28, 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of Pepco, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs. FERC reduced the ROE applicable to the abandoned costs from the previously approved 12.8% incentive ROE to 10.8% by disallowing 200 basis points of ROE adders. FERC also denied recovery of 50% (calculated by Pepco to be $1 million) of the prudently incurred abandoned costs prior to November 1, 2008, the date of FERC's MAPP incentive order. Pepco believes that the February 2013 FERC order is not consistent with prior precedent and is vigorously pursuing its rights to recover all prudently incurred abandoned costs associated with the MAPP project, as well as the full ROE previously approved by FERC. On April 1, 2013, PHI filed a rehearing request on behalf of Pepco of the February 28, 2013 FERC order challenging the reduction of the ROE applicable to the abandoned costs, as well as the denial of 50% of the costs incurred prior to November 1, 2008. On that same date, a group of public advocates from Maryland, Delaware, New Jersey, Virginia, West Virginia and Pennsylvania also filed a rehearing request challenging the 10.8% ROE authorized in FERC's order, arguing that Pepco is not entitled to any rate of return on the abandoned costs and that FERC improperly failed to set the ROE for hearing. Pepco is currently engaged in settlement negotiations in this matter; however, Pepco cannot predict when a final FERC decision in this proceeding will be issued.

As of September 30, 2013, Pepco had a regulatory asset related to the MAPP abandoned costs of $39 million, representing the original filing amount of approximately $50 million of abandoned costs referred to above less: (i) approximately $1 million of disallowed costs written off in 2013; (ii) $5 million of materials transferred to inventories for use on other projects; and (iii) $5 million of amortization expense recorded in 2013. The regulatory asset balance includes the costs of land, land rights, engineering and design, environmental services, and project management and administration. Pepco intends to reduce further the amount of the regulatory asset by any amounts recovered from the sale or alternative use of the land.

Transmission ROE Challenge

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey filed a joint complaint with FERC against Pepco, DPL and Atlantic City Electric Company (ACE), an affiliate of Pepco, as well as BGE. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that Pepco provides. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for Pepco is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. Pepco believes the allegations in this complaint are without merit and is vigorously contesting it. On April 3, 2013, Pepco filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable.

(7) <u>PENSION AND OTHER POSTRETIREMENT BENEFITS</u>

Pepco accounts for its participation in its parent's single-employer plans, Pepco Holdings' non-contributory retirement plan (the PHI Retirement Plan) and the Pepco Holdings, Inc. Welfare Plan for Retirees, as participation in multiemployer plans. PHI's pension and other postretirement net periodic benefit cost for the three months ended September 30, 2013 and 2012, before intercompany allocations from the PHI Service Company, were $20 million and $28 million, respectively. Pepco's allocated share was $8 million and $10 million, respectively, for the three months ended September 30, 2013 and 2012. PHI's pension and other postretirement net periodic benefit cost for the nine months ended September 30, 2013 and 2012, before intercompany allocations from the PHI Service Company, were $74 million and $84 million, respectively. Pepco's allocated share of the net periodic benefit cost was $27 million and $30 million, respectively, for the nine months ended September 30, 2013 and 2012.

In the first quarter of 2012, Pepco made a discretionary tax-deductible contribution to the PHI Retirement Plan of $85 million.

Other Postretirement Benefit Plan Amendment

During 2013, PHI approved two amendments to its other postretirement benefits plan. These amendments impacted the retiree medical plan and the retiree life insurance benefits, and will be effective on January 1, 2014. As a result of the amendments, which were cumulatively significant, PHI remeasured its projected benefit obligation for other postretirement benefits as of July 1, 2013. The remeasurement is expected to result in a $4 million reduction in Pepco's net periodic benefit cost for other postretirement benefits during 2013. Approximately 30% of net periodic other postretirement benefit costs are capitalized.

(8) <u>DEBT</u>

Credit Facility

PHI, Pepco, DPL and ACE maintain an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. On August 1, 2011, PHI, Pepco, DPL and ACE entered into an amended and restated credit agreement which, on August 2, 2012, was amended to extend the term of the credit facility to August 1, 2017 and to amend the pricing schedule to decrease certain fees and interest rates payable to the lenders under the facility. On June 6, 2013, as permitted under the existing terms of the credit agreement, PHI, Pepco, DPL and ACE provided to the agent and lenders under the credit agreement, a notice requesting a one-year extension of the credit facility termination date. The request was approved and the new termination date is August 1, 2018. All of the terms and conditions as well as pricing remain the same.

The aggregate borrowing limit under the amended and restated credit facility is $1.5 billion, all or any portion of which may be used to obtain loans and up to $500 million of which may be used to obtain letters of credit. The facility also includes a swingline loan sub-facility, pursuant to which each company may make same day borrowings in an aggregate amount not to exceed 10% of the total amount of the facility. Any swingline loan must be repaid by the borrower within fourteen days of receipt. The credit sublimit is $750 million for PHI and $250 million for each of Pepco, DPL and ACE. The sublimits may be increased or decreased by the individual borrower during the term of the facility, except that (i) the sum of all of the borrower sublimits following any such increase or decrease must equal the total amount of the facility and (ii) the aggregate amount of credit used at any given time by (a) PHI may not exceed $1.25 billion and (b) each of Pepco, DPL or ACE may not exceed the lesser of $500 million and the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the sublimit reallocations may not exceed eight per year during the term of the facility.

The interest rate payable by each company on utilized funds is, at the borrowing company's election, (i) the greater of the prevailing prime rate, the federal funds effective rate plus 0.5% and the one month London Interbank Offered Rate plus 1.0%, or (ii) the prevailing Eurodollar rate, plus a margin that varies according to the credit rating of the borrower.

In order for a borrower to use the facility, certain representations and warranties must be true and correct, and the borrower must be in compliance with specified financial and other covenants, including (i) the requirement that each borrowing company maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the credit agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) with certain exceptions, a restriction on sales or other dispositions of assets, and (iii) a restriction on the incurrence of liens on the assets of a borrower or any of its significant subsidiaries other than permitted liens. The credit agreement contains certain covenants and other customary agreements and requirements that, if not complied with, could result in an event of default and the acceleration of repayment obligations of one or more of the borrowers thereunder. Each of the borrowers was in compliance with all covenants under this facility as of September 30, 2013.

The absence of a material adverse change in PHI's business, property, results of operations or financial condition is not a condition to the availability of credit under the credit agreement. The credit agreement does not include any rating triggers.

As of September 30, 2013 and December 31, 2012, the amount of cash plus borrowing capacity under the credit facility available to meet the liquidity needs of PHI's utility subsidiaries in the aggregate was $471 million and $477 million, respectively. Pepco's borrowing capacity under the credit facility at any given time depends on the amount of the subsidiary borrowing capacity being utilized by DPL and ACE and the portion of the total capacity being used by PHI.

Commercial Paper

Pepco maintains an on-going commercial paper program to address its short-term liquidity needs. As of September 30, 2013, the maximum capacity available under the program was $500 million, subject to available borrowing capacity under the credit facility.

Pepco had $32 million of commercial paper outstanding at September 30, 2013. The weighted average interest rate for commercial paper issued by Pepco during the nine months ended September 30, 2013 was 0.37% and the weighted average maturity of all commercial paper issued by Pepco during the nine months ended September 30, 2013 was six days.

(9) INCOME TAXES

A reconciliation of Pepco's effective income tax rates is as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2013		2012		2013		2012	
	(millions of dollars)							
Income tax at Federal statutory rate	$ 37	35.0%	$ 30	35.0%	$ 66	35.0%	$ 49	35.0%
Increases (decreases) resulting from:								
State income taxes, net of Federal effect	6	5.7%	5	5.9%	11	5.9%	8	5.8%
Asset removal costs	(5)	(4.7)%	(1)	(1.2)%	(11)	(5.9)%	(8)	(5.8)%
Change in estimates and interest related to uncertain and effectively settled tax positions	—	—	—	—	(4)	(2.1)%	(11)	(7.9)%
Permanent differences related to deferred compensation funding	—	—	—	—	—	—	(1)	(0.7)%
Tax credits	—	—	—	—	—	—	(1)	(0.7)%
Other, net	2	1.7%	1	1.5%	—	0.1%	2	1.6%
Income tax expense	$ 40	37.7%	$ 35	41.2%	$ 62	33.0%	$ 38	27.3%

Three Months Ended September 30, 2013 and 2012

Pepco's effective tax rates for the three months ended September 30, 2013 and 2012 and were 37.7% and 41.2%, respectively. The decrease in the effective tax rate primarily resulted from an increase in asset removal costs.

Nine Months Ended September 30, 2013 and 2012

Pepco's effective tax rates for the nine months ended September 30, 2013 and 2012 were 33.0% and 27.3%, respectively. The increase in the effective tax rate primarily resulted from changes in estimates and interest related to uncertain and effectively settled tax positions.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which Pepco is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. As a result of the court's ruling in this case, PHI determined in the first quarter of 2013 that it could no longer support its current assessment with respect to the likely outcome of tax positions associated with its cross-border energy lease investments held by its wholly-owned subsidiary Potomac Capital Investment Corporation, and PHI recorded a charge of $377 million (after-tax) in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $54 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in Pepco recording a $5 million interest benefit in the first quarter of 2013.

In the first quarter of 2012, Pepco recorded benefits of $11 million for changes in estimates and interest related to uncertain and effectively settled tax positions primarily due to the effective settlement with the Internal Revenue Service (IRS) with respect to the methodology used historically to calculate deductible mixed service costs and the expiration of the statute of limitations associated with an uncertain tax position.

Final IRS Regulations on Repair of Tangible Property

In September 2013, the IRS issued final regulations on expense versus capitalization of repairs with respect to tangible personal property. The regulations are effective for tax years beginning on or after January 1, 2014, and provide an option to early adopt the final regulations for tax years beginning on or after January 1, 2012.

It is expected that the IRS will issue revenue procedures that will describe how taxpayers may implement the final regulations. The final repair regulations retain the operative rule that the Unit of Property for network assets is determined by the taxpayer's particular facts and circumstances except as provided in published guidance. In 2012, with the filing of its 2011 tax return, PHI filed a request for an automatic change in accounting method related to repairs of its network assets in accordance with IRS Revenue Procedure 2011-43. Pepco does not expect the effects of the final regulations to be significant and will continue to evaluate the impact of the new guidance on its financial statements.

(10) FAIR VALUE DISCLOSURES

Financial Instruments Measured at Fair Value on a Recurring Basis

Pepco applies FASB guidance on fair value measurement and disclosures (ASC 820) that established a framework for measuring fair value and expanded disclosures about fair value measurements. As defined in the guidance, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Pepco utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. Accordingly, Pepco utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1) and the lowest priority to unobservable inputs (level 3).

The following tables set forth, by level within the fair value hierarchy, Pepco's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2013 and December 31, 2012. As required by the guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Pepco's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair Value Measurements at September 30, 2013			
Description	**Total**	**Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)**	**Significant Other Observable Inputs (Level 2) (a)**	**Significant Unobservable Inputs (Level 3)**
		(millions of dollars)		
ASSETS				
Cash equivalents				
Treasury fund	$ 3	$ 3	$ —	$ —
Executive deferred compensation plan assets				
Money market funds	15	15	—	—
Life insurance contracts	57	—	40	17
	$ 75	$ 18	$ 40	$ 17
LIABILITIES				
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 8	$ —	$ 8	$ —
	$ 8	$ —	$ 8	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the nine months ended September 30, 2013.

Description	Total	Fair Value Measurements at December 31, 2012		
		Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
		(millions of dollars)		
ASSETS				
Executive deferred compensation plan assets				
Money market funds	$ 15	$ 15	$ —	$ —
Life insurance contracts	56	—	38	18
	$ 71	$ 15	$ 38	$ 18
LIABILITIES				
Executive deferred compensation plan liabilities				
Life insurance contracts	$ 9	$ —	$ 9	$ —
	$ 9	$ —	$ 9	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2012.

Pepco classifies its fair value balances in the fair value hierarchy based on the observability of the inputs used in the fair value calculation as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using broker quotes in liquid markets and other observable data. Level 2 also includes those financial instruments that are valued using methodologies that have been corroborated by observable market data through correlation or by other means. Significant assumptions are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Executive deferred compensation plan assets and liabilities categorized as level 2 consist of life insurance policies and certain employment agreement obligations. The life insurance policies are categorized as level 2 assets because they are valued based on the assets underlying the policies, which consist of short-term cash equivalents and fixed income securities that are priced using observable market data and can be liquidated for the value of the underlying assets as of September 30, 2013. The level 2 liability associated with the life insurance policies represents a deferred compensation obligation, the value of which is tracked via underlying insurance sub-accounts. The sub-accounts are designed to mirror existing mutual funds and money market funds that are observable and actively traded.

The value of certain employment agreement obligations (which are included with life insurance contracts in the tables above) is derived using a discounted cash flow valuation technique. The discounted cash flow calculations are based on a known and certain stream of payments to be made over time that are discounted to determine their net present value. The primary variable input, the discount rate, is based on market-corroborated and observable published rates. These obligations have been classified as level 2 within the fair value hierarchy because the payment streams represent contractually known and certain amounts and the discount rate is based on published, observable data.

Level 3 – Pricing inputs that are significant and generally less observable than those from objective sources. Level 3 includes those financial instruments that are valued using models or other valuation methodologies.

Executive deferred compensation plan assets include certain life insurance policies that are valued using the cash surrender value of the policies, net of loans against those policies. The cash surrender values do not represent a quoted price in an active market; therefore, those inputs are unobservable and the policies are categorized as level 3. Cash surrender values are provided by third parties and reviewed by Pepco for reasonableness.

Reconciliations of the beginning and ending balances of Pepco's fair value measurements using significant unobservable inputs (level 3) for the nine months ended September 30, 2013 and 2012, are shown below:

	Life Insurance Contracts	
	Nine Months Ended September 30,	
	2013	2012
	(millions of dollars)	
Beginning balance as of January 1	$ 18	$ 17
Total gains (losses) (realized and unrealized):		
Included in income	3	3
Included in accumulated other comprehensive loss	—	—
Purchases	—	—
Issuances	(3)	(3)
Settlements	(1)	—
Transfers in (out) of level 3	—	—
Ending balance as of September 30	$ 17	$ 17

The breakdown of realized and unrealized gains on level 3 instruments included in income as a component of Other Operation and Maintenance expense for the periods below were as follows:

	Nine Months Ended September 30,	
	2013	2012
	(millions of dollars)	
Total gains included in income for the period	$ 3	$ 3
Change in unrealized gains relating to assets still held at reporting date	$ 3	$ 3

Other Financial Instruments

The estimated fair values of Pepco's debt instruments that are measured at amortized cost in Pepco's financial statements and the associated level of the estimates within the fair value hierarchy as of September 30, 2013 and December 31, 2012 are shown in the tables below. As required by the fair value measurement guidance, debt instruments are classified in their entirety within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. Pepco's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, which may affect the valuation of fair value debt instruments and their placement within the fair value hierarchy levels.

The fair value of Long-term debt categorized as level 2 is based on a blend of quoted prices for the debt and quoted prices for similar debt on the measurement date. The blend places more weight on current pricing information when determining the final fair value measurement. The fair value information is provided by brokers and Pepco reviews the methodologies and results.

	Fair Value Measurements at September 30, 2013			
Description	**Total**	**Quoted Prices in Active Markets for Identical Instruments (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		(millions of dollars)		
LIABILITIES				
Debt instruments				
Long-term debt (a)	$2,237	$ —	$ 2,237	$ —
	$2,237	$ —	$ 2,237	$ —

(a) The carrying amount for Long-term debt is $1,950 million as of September 30, 2013.

	Fair Value Measurements at December 31, 2012			
Description	**Total**	**Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)**	**Significant Other Observable Inputs (Level 2) (a)**	**Significant Unobservable Inputs (Level 3)**
		(millions of dollars)		
LIABILITIES				
Debt instruments				
Long-term debt (b)	$2,160	$ —	$ 2,160	$ —
	$2,160	$ —	$ 2,160	$ —

(a) Certain debt instruments that were categorized as level 1 at December 31, 2012, have been reclassified as level 2 to conform to the current period presentation.
(b) The carrying amount for Long-term debt is $1,701 million as of December 31, 2012.

The carrying amounts of all other financial instruments in the accompanying financial statements approximate fair value.

(11) COMMITMENTS AND CONTINGENCIES

Environmental Matters

Pepco is subject to regulation by various federal, regional, state and local authorities with respect to the environmental effects of its operations, including air and water quality control, solid and hazardous waste disposal and limitations on land use. Although penalties assessed for violations of environmental laws and regulations are not recoverable from customers of Pepco, environmental clean-up costs incurred by Pepco generally are included in its cost of service for ratemaking purposes. The total accrued liabilities for the environmental contingencies of Pepco described below at September 30, 2013 are summarized as follows:

	Transmission and Distribution	Legacy Generation - Regulated	Total
	(millions of dollars)		
Beginning balance as of January 1	$ 14	$ 3	$ 17
Accruals	4	—	4
Payments	1	—	1
Ending balance as of September 30	17	3	20
Less amounts in Other Current Liabilities	2	—	2
Amounts in Other deferred credits	$ 15	$ 3	$ 18

Peck Iron and Metal Site

The U.S. Environmental Protection Agency (EPA) informed Pepco in a May 2009 letter that Pepco may be a potentially responsible party (PRP) under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) with respect to the cleanup of the Peck Iron and Metal site in Portsmouth, Virginia, and for costs EPA has incurred in cleaning up the site. The EPA letter states that Peck Iron and Metal purchased, processed, stored and shipped metal scrap from military bases, governmental agencies and businesses and that Peck's metal scrap operations resulted in the improper storage and disposal of hazardous substances. EPA bases its allegation that Pepco arranged for disposal or treatment of hazardous substances sent to the site on information provided by former Peck Iron and Metal personnel, who informed EPA that Pepco was a customer at the site. Pepco has advised EPA by letter that its records show no evidence of any sale of scrap metal by Pepco to the site. Even if EPA has such records and such sales did occur, Pepco believes that any such scrap metal sales may be entitled to the recyclable material exemption from CERCLA liability. In a Federal Register notice published on November 4, 2009, EPA placed the Peck Iron and Metal site on the National Priorities List. The National Priorities List, among other things, serves as a guide to EPA in determining which sites warrant further investigation to assess the nature and extent of the human health and environmental risks associated with a site. In September 2011, EPA initiated a remedial investigation/feasibility study (RI/FS) using federal funds. Pepco cannot at this time estimate an amount or range of reasonably possible loss associated with the RI/FS, any remediation activities to be performed at the site or any other costs that EPA might seek to impose on Pepco.

Ward Transformer Site

In April 2009, a group of PRPs with respect to the Ward Transformer site in Raleigh, North Carolina, filed a complaint in the U.S. District Court for the Eastern District of North Carolina, alleging cost recovery and/or contribution claims against a number of entities, including Pepco, based on its alleged sale of transformers to Ward Transformer, with respect to past and future response costs incurred by the PRP group in performing a removal action at the site. In a March 2010 order, the court denied the defendants' motion to dismiss. The litigation is moving forward with certain "test case" defendants (not including Pepco) filing summary judgment motions regarding liability. The case has been stayed as to the remaining defendants pending rulings upon the test cases. In a January 31, 2013 order, the district court granted summary judgment for the test case defendant whom plaintiffs alleged was liable based on its sale of transformers to Ward Transformer. The district court's order, which plaintiffs have appealed to the U.S. Court of Appeals for the Fourth Circuit, addresses only the liability of the test case defendant. Pepco has concluded that a loss is reasonably possible with respect to this matter, but was unable to estimate an amount or range of reasonably possible losses to which it may be exposed. Pepco does not believe that it had extensive business transactions, if any, with the Ward Transformer site.

Benning Road Site

In September 2010, PHI received a letter from EPA identifying the Benning Road location, consisting of a generation facility operated by Pepco Energy Services until the facility was deactivated in June 2012, and a transmission and distribution facility operated by Pepco, as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. The letter stated that the principal contaminants of concern are polychlorinated biphenyls and polycyclic aromatic hydrocarbons. In December 2011, the U.S. District Court for the District of Columbia approved a consent decree entered into by Pepco and Pepco Energy Services with the District of Columbia Department of the Environment (DDOE), which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10-15 acre portion of the adjacent Anacostia River. The RI/FS will form the basis for DDOE's selection of a remedial action for the Benning Road site and for the Anacostia River sediment associated with the site. The consent decree does not obligate Pepco or Pepco Energy Services to pay for or perform any remediation work, but it is anticipated that DDOE will look to the companies to assume responsibility for cleanup of any conditions in the river that are determined to be attributable to past activities at the Benning Road site.

In December 2012, DDOE approved the RI/FS work plan. RI/FS field work commenced in January 2013 and is still in progress. The final permit to authorize sampling in the river was issued in September 2013, and that sampling work is expected to be completed during the fourth quarter of 2013. In October 2013, Pepco and Pepco Energy Services submitted a work plan addendum for approval by DDOE identifying the location of groundwater monitoring wells to be installed at the site and sampled as the last phase of the field work. Following the field work, Pepco and Pepco Energy Services will prepare RI/ FS reports for review and approval by DDOE after solicitation and consideration of public comment. The next status report to the court is due on May 24, 2014.

The remediation costs accrued for this matter are included in the table above in the columns entitled "Transmission and Distribution" and "Legacy Generation – Regulated."

Potomac River Mineral Oil Release

In January 2011, a coupling failure on a transformer cooler pipe resulted in a release of non-toxic mineral oil at Pepco's Potomac River substation in Alexandria, Virginia. An overflow of an underground secondary containment reservoir resulted in approximately 4,500 gallons of mineral oil flowing into the Potomac River.

Beginning in March 2011, DDOE issued a series of compliance directives requiring Pepco to prepare an incident report, provide certain records, and prepare and implement plans for sampling surface water and river sediments and assessing ecological risks and natural resources damages. Pepco completed field sampling during the fourth quarter of 2011 and submitted sampling results to DDOE during the second quarter of 2012. Pepco is continuing discussions with DDOE regarding the need for any further response actions but expects that additional monitoring of shoreline sediments may be required.

In June 2012, Pepco commenced discussions with DDOE regarding a possible consent decree that would resolve DDOE's threatened enforcement action, including civil penalties, for alleged violation of the District's Water Pollution Control Law, as well as for damages to natural resources. Pepco and DDOE have reached an agreement in principle that would consist of a combination of a civil penalty and Supplemental Environmental Projects (SEPs) with a total cost to Pepco of approximately $1 million. DDOE has endorsed

Pepco's proposed SEP involving the installation and operation of a trash collection system at a stormwater outfall that drains to the Anacostia River. DDOE and Pepco will negotiate a consent decree to document the settlement of DDOE's enforcement action. Discussions will proceed separately with DDOE and the federal resource trustees regarding the settlement of a natural resource damage (NRD) claim under federal law. Based on discussions to date, PHI and Pepco do not believe that the resolution of DDOE's enforcement action or the federal NRD claim will have a material adverse effect on their respective financial condition, results of operations or cash flows.

As a result of the oil release, Pepco implemented certain interim operational changes to the secondary containment systems at the facility which involve pumping accumulated storm water to an aboveground holding tank for off-site disposal. In December 2011, Pepco completed the installation of a treatment system designed to allow automatic discharge of accumulated storm water from the secondary containment system. Pepco currently is seeking DDOE's and EPA's approval to commence operation of the new system on a pilot basis to demonstrate its effectiveness in meeting both secondary containment requirements and water quality standards related to the discharge of storm water from the facility. In the meantime, Pepco is continuing to use the aboveground holding tank to manage storm water from the secondary containment system.

The amount accrued for this matter is included in the table above in the column entitled "Transmission and Distribution."

Metal Bank Site

In January 2013, the National Oceanic and Atmospheric Administration (NOAA) contacted Pepco on behalf of itself and other federal and state trustees to request that Pepco execute a tolling agreement to facilitate settlement negotiations concerning natural resource damages allegedly caused by releases of hazardous substances, including polychlorinated biphenyls, at the Metal Bank Superfund Site located in Philadelphia, Pennsylvania. Pepco has executed the tolling agreement and will participate in settlement discussions with the NOAA, the trustees and other PRPs.

The amount accrued for this matter is included in the table above in the column entitled "Transmission and Distribution."

Brandywine Fly Ash Disposal Site

In February 2013, Pepco received a letter from the Maryland Department of the Environment (MDE) requesting that Pepco investigate the extent of waste on a Pepco right-of-way that traverses the Brandywine fly ash disposal site in Brandywine, Prince George's County, Maryland, owned by GenOn MD Ash Management, LLC (GenOn). The letter requests that Pepco submit a plan of action for the investigation and capping of the right-of-way within 90 days. In its February 2013 response, Pepco informed MDE that, under a 2000 asset purchase and sale agreement (the Sale Agreement), the buyer of Pepco's generation assets assumed environmental liability for hazardous substances, including ash, which remain on or have been removed from the land on which the generating stations are situated. In July 2013, Pepco received a letter from the Maryland Attorney General's office on behalf of MDE, which takes the position that agreements between private parties do not operate to shift responsibility for compliance with landfill closure regulations and that Pepco, as the former owner and operator of a portion of the landfill, is responsible for compliance with closure requirements for that portion. The letter urges Pepco to work with GenOn concerning a closure plan and cap for the entire landfill and indicates that, absent an agreement between Pepco and GenOn concerning a closure plan and cap for the entire landfill or Pepco's submission of a plan to investigate and cap the portion of the landfill that Pepco owns, MDE will take formal action against Pepco to enforce the landfill closure regulations. In its July 22, 2013 response to the Maryland Attorney General's office, Pepco indicated, while reserving its rights under the Sale Agreement, its willingness to investigate the extent of, and propose an appropriate closure plan to address, ash on the right-of-way. Pepco submitted a schedule for development of a closure plan to MDE on September 30, 2013, which was approved on October 18, 2013.

Pepco has determined that a loss associated with this matter is probable and has estimated that the costs for implementation of a closure plan and cap on the site are in the range of approximately $3 million to $6 million. Pepco believes that the costs incurred in this matter will be recoverable from GenOn under the Sale Agreement.

The amount accrued for this matter is included in the table above in the column entitled "Transmission and Distribution."

Watts Branch Insulating Fluid Release

On September 13, 2013, a Washington Metropolitan Area Transit Authority (WMATA) contractor damaged a Pepco underground transmission feeder while drilling a grout column for a subway tunnel under a city street. The damage caused the release of approximately 11,250 gallons of insulating fluid, a small amount of which reached the Watts Branch, a tributary of the Anacostia River. Pepco responded to the release of the insulating fluid. The U.S. Coast Guard (USCG) issued a notice of federal interest for an oil pollution incident, informing Pepco of its responsibility under the Oil Pollution Act of 1990 for removal costs and damages from the release and indicating that USCG would take Pepco's response actions into account in determining the penalty that may be assessed as a result of the release. In addition, on September 25, 2013, DDOE issued a compliance directive that requires Pepco to prepare an incident investigation report describing the events leading up to the release. The compliance directive also requires Pepco to prepare work plans for sampling the insulating fluid and for developing and implementing a biological assessment and physical habitat quality assessment to be conducted in Watts Branch. Pepco prepared the incident investigation report and work plans and submitted them to DDOE and USCG.

Pepco believes that a loss in this matter is probable; however, the costs to resolve this matter are expected to be less than $1 million and are being expensed as incurred. Pepco further believes that the costs incurred will be recoverable from the party or parties responsible for the release.

(12) RELATED PARTY TRANSACTIONS

PHI Service Company provides various administrative and professional services to PHI and its regulated and unregulated subsidiaries, including Pepco. The cost of these services is allocated in accordance with cost allocation methodologies set forth in the service agreement using a variety of factors, including the subsidiaries' share of employees, operating expenses, assets and other cost methods. These intercompany transactions are eliminated by PHI in consolidation and no profit results from these transactions at PHI. PHI Service Company costs directly charged or allocated to Pepco for the three months ended September 30, 2013 and 2012 were approximately $50 million and $55 million, respectively. PHI Service Company costs directly charged or allocated to Pepco for the nine months ended September 30, 2013 and 2012 were approximately $157 million and $158 million, respectively.

Pepco Energy Services performs utility maintenance services and high voltage underground transmission cabling, including services that are treated as capital costs, for Pepco. Amounts charged to Pepco by Pepco Energy Services for each of the three months ended September 30, 2013 and 2012 were approximately $4 million. Amounts charged to Pepco by Pepco Energy Services for the nine months ended September 30, 2013 and 2012 were approximately $16 million and $14 million, respectively.

As of September 30, 2013 and December 31, 2012, Pepco had the following balances on its balance sheets due to related parties:

	September 30, 2013	December 31, 2012
	(millions of dollars)	
Payable to Related Party (current) (a)		
PHI Service Company	$ (25)	$ (22)
Pepco Energy Services (b)	(6)	(18)
Other	—	(1)
Total	$ (31)	$ (41)

(a) Included in Accounts Payable Due to Associated Companies.

(b) Pepco bills customers on behalf of Pepco Energy Services where customers have selected Pepco Energy Services as their alternative energy supplier or where Pepco Energy Services has performed work for certain government agencies under a General Services Administration area-wide agreement. Amount also includes charges for utility work performed by Pepco Energy Services on behalf of Pepco.

DELMARVA POWER & LIGHT COMPANY
STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
	(millions of dollars)			
Operating Revenue				
Electric	$ 273	$ 314	$ 795	$ 808
Natural gas	23	26	137	124
Total Operating Revenue	296	340	932	932
Operating Expenses				
Purchased energy	142	178	422	443
Gas purchased	11	15	80	77
Other operation and maintenance	59	65	191	192
Depreciation and amortization	27	29	79	78
Other taxes	10	10	29	26
Total Operating Expenses	249	297	801	816
Operating Income	47	43	131	116
Other Income (Expenses)				
Interest expense	(13)	(12)	(38)	(34)
Other income	3	2	7	8
Total Other Expenses	(10)	(10)	(31)	(26)
Income Before Income Tax Expense	37	33	100	90
Income Tax Expense	14	11	39	34
Net Income	$ 23	$ 22	$ 61	$ 56

The accompanying Notes are an integral part of these Financial Statements.

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

	September 30, 2013	December 31, 2012
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 4	$ 6
Accounts receivable, less allowance for uncollectible accounts of $13 million and $9 million, respectively	175	201
Inventories	63	53
Prepayments of income taxes	10	10
Income taxes receivable	5	10
Assets and accrued interest related to uncertain tax positions	18	—
Prepaid expenses and other	22	20
Total Current Assets	297	300
INVESTMENTS AND OTHER ASSETS		
Goodwill	8	8
Regulatory assets	303	288
Prepaid pension expense	231	232
Assets and accrued interest related to uncertain tax positions	3	20
Other	13	12
Total Investments and Other Assets	558	560
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	3,592	3,422
Accumulated depreciation	(1,012)	(1,000)
Net Property, Plant and Equipment	2,580	2,422
TOTAL ASSETS	$ 3,435	$ 3,282

The accompanying Notes are an integral part of these Financial Statements.

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

	September 30, 2013	December 31, 2012
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 255	$ 137
Current portion of long-term debt	250	250
Accounts payable and accrued liabilities	87	125
Accounts payable due to associated companies	21	20
Taxes accrued	6	4
Interest accrued	15	6
Derivative liabilities	—	4
Other	66	61
Total Current Liabilities	700	607
DEFERRED CREDITS		
Regulatory liabilities	238	258
Deferred income tax liabilities, net	748	697
Investment tax credits	5	5
Other postretirement benefit obligations	25	22
Other	36	41
Total Deferred Credits	1,052	1,023
LONG-TERM LIABILITIES		
Long-term debt	667	667
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
EQUITY		
Common stock, $2.25 par value, 1,000 shares authorized, 1,000 shares outstanding	—	—
Premium on stock and other capital contributions	407	407
Retained earnings	609	578
Total Equity	1,016	985
TOTAL LIABILITIES AND EQUITY	$ 3,435	$ 3,282

The accompanying Notes are an integral part of these Financial Statements.

DELMARVA POWER & LIGHT COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2013	2012
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 61	$ 56
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	79	78
Deferred income taxes	48	44
Changes in:		
Accounts receivable	26	(6)
Inventories	(10)	(11)
Regulatory assets and liabilities, net	(35)	(16)
Accounts payable and accrued liabilities	(21)	2
Pension contributions	(10)	(85)
Income tax-related prepayments, receivables and payables	—	11
Interest accrued	9	8
Other assets and liabilities	10	7
Net Cash From Operating Activities	157	88
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(249)	(219)
Net other investing activities	1	(4)
Net Cash Used By Investing Activities	(248)	(223)
FINANCING ACTIVITIES		
Dividends paid to Parent	(30)	—
Capital contribution from Parent	—	60
Issuances of long-term debt	—	250
Reacquisitions of long-term debt	—	(97)
Issuances (repayments) of short-term debt, net	118	(47)
Cost of issuances	—	(3)
Net other financing activities	1	8
Net Cash From Financing Activities	89	171
Net (Decrease) Increase in Cash and Cash Equivalents	(2)	36
Cash and Cash Equivalents at Beginning of Period	6	5
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 4	$ 41
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash received for income taxes (includes payments from PHI for federal income taxes)	$ (8)	$ (24)
Non-cash activities:		
Reclassification of property, plant and equipment to regulatory assets	—	37
Reclassification of asset removal costs regulatory liability to accumulated depreciation	—	42

The accompanying Notes are an integral part of these Financial Statements.

DELMARVA POWER & LIGHT COMPANY
STATEMENT OF EQUITY
(Unaudited)

(millions of dollars, except shares)	Common Stock Shares	Common Stock Par Value	Premium on Stock	Retained Earnings	Total
BALANCE, DECEMBER 31, 2012	1,000	$ —	$ 407	$ 578	$ 985
Net Income	—	—	—	26	26
BALANCE, MARCH 31, 2013	1,000	—	407	604	1,011
Net Income	—	—	—	12	12
Dividends on common stock	—	—	—	(20)	(20)
BALANCE, JUNE 30, 2013	1,000	—	407	596	1,003
Net Income	—	—	—	23	23
Dividends on common stock	—	—	—	(10)	(10)
BALANCE, SEPTEMBER 30, 2013	1,000	$ —	$ 407	$ 609	$1,016

The accompanying Notes are an integral part of these Financial Statements.

NOTES TO FINANCIAL STATEMENTS

DELMARVA POWER & LIGHT COMPANY

(1) ORGANIZATION

Delmarva Power & Light Company (DPL) is engaged in the transmission and distribution of electricity in Delaware and portions of Maryland and provides natural gas distribution service in northern Delaware. Additionally, DPL provides Default Electricity Supply, which is the supply of electricity at regulated rates to retail customers in its service territories who do not elect to purchase electricity from a competitive supplier. Default Electricity Supply is known as Standard Offer Service in both Delaware and Maryland. DPL is a wholly owned subsidiary of Conectiv, LLC, which is wholly owned by Pepco Holdings, Inc. (Pepco Holdings or PHI).

(2) SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation

DPL's unaudited financial statements are prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). Pursuant to the rules and regulations of the Securities and Exchange Commission, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with GAAP have been omitted. Therefore, these financial statements should be read along with the annual financial statements included in DPL's annual report on Form 10-K for the year ended December 31, 2012. In the opinion of DPL's management, the unaudited financial statements contain all adjustments (which all are of a normal recurring nature) necessary to state fairly DPL's financial condition as of September 30, 2013, in accordance with GAAP. The year-end December 31, 2012 balance sheet included herein was derived from audited financial statements, but does not include all disclosures required by GAAP. Interim results for the three and nine months ended September 30, 2013 may not be indicative of DPL's results that will be realized for the full year ending December 31, 2013.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities in the financial statements and accompanying notes. Although DPL believes that its estimates and assumptions are reasonable, they are based upon information available to management at the time the estimates are made. Actual results may differ significantly from these estimates.

Significant matters that involve the use of estimates include the assessment of contingencies, future cash flows and fair value amounts for use in asset and goodwill impairment evaluations, fair value calculations for derivative instruments, pension and other postretirement benefits assumptions, the assessment of the probability of recovery of regulatory assets, accrual of storm restoration costs, accrual of unbilled revenue, recognition of changes in network service transmission rates for prior service year costs, accrual of self-insurance reserves for general and auto liability claims, and income tax provisions and reserves. Additionally, DPL is subject to legal, regulatory and other proceedings and claims that arise in the ordinary course of its business. DPL records an estimated liability for these proceedings and claims when it is probable that a loss has been incurred and the loss is reasonably estimable.

Consolidation of Variable Interest Entities - DPL Renewable Energy Transactions

DPL assesses its contractual arrangements with variable interest entities to determine whether it is the primary beneficiary and thereby has to consolidate the entities in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 810. The guidance addresses conditions under which an entity should be consolidated based upon variable interests rather than voting interests.

DPL is subject to Renewable Energy Portfolio Standards (RPS) in the state of Delaware that require it to obtain renewable energy credits (RECs) for energy delivered to its customers. DPL's costs associated with obtaining RECs to fulfill its RPS obligations are recoverable from its customers by law. As of September 30, 2013, DPL is a party to three land-based wind power purchase agreements (PPAs) in the aggregate amount of 128 megawatts (MWs) and one solar PPA with a 10 MW facility. Each of the facilities associated with these PPAs is operational, and DPL is obligated to purchase energy and RECs in amounts generated and delivered by the wind facilities and solar renewable energy credits (SRECs) from the solar facility up to certain amounts (as set forth below) at rates that are primarily fixed under the respective PPA. PHI has concluded that consolidation is not required for any of these PPAs under the FASB guidance on the consolidation of variable interest entities.

DPL is obligated to purchase energy and RECs from one of the wind facilities through 2024 in amounts not to exceed 50 MWs, from the second wind facility through 2031 in amounts not to exceed 40 MWs, and from the third wind facility through 2031 in amounts not to exceed 38 MWs. DPL's purchases under the three wind PPAs totaled $4 million for each of the three months ended September 30, 2013 and 2012. DPL's purchases under the three wind PPAs totaled $21million and $20 million for the nine months ended September 30, 2013 and 2012, respectively.

The term of the agreement with the solar facility is 20 years and DPL is obligated to purchase SRECs in an amount up to 70 percent of the energy output at a fixed price. DPL's purchases under the solar agreement were $1 million for each of the three months ended September 30, 2013 and 2012. DPL's purchases under the solar agreement were $2 million for each of the nine months ended September 30, 2013 and 2012.

On October 18, 2011, the Delaware Public Service Commission (DPSC) approved a tariff submitted by DPL in accordance with the requirements of the RPS specific to fuel cell facilities totaling 30 MWs to be constructed by a qualified fuel cell provider. The tariff and the RPS establish that DPL is an agent to collect payments in advance from its distribution customers and remit them to the qualified fuel cell provider for each MW hour (MWh) of energy produced by the fuel cell facilities over 21 years. DPL has no obligation to the qualified fuel cell provider other than to remit payments collected from its distribution customers pursuant to the tariff. The RPS provides for a reduction in DPL's REC requirements based upon the actual energy output of the facilities. At September 30, 2013 and 2012, 15 MWs and 3MWs of capacity were available from fuel cell facilities placed in service under the tariff, respectively. DPL billed $7 million and less than $1 million to distribution customers for the three months ended September 30, 2013 and 2012, respectively. DPL billed $13 million and less than $1 million to distribution customers for the nine months ended September 30, 2013 and 2012, respectively. DPL has concluded that consolidation under the variable interest entity consolidation guidance is not required for this arrangement.

Goodwill

Goodwill represents the excess of the purchase price of an acquisition over the fair value of the net assets acquired at the acquisition date. All of DPL's goodwill was generated by DPL's acquisition of Conowingo Power Company in 1995. DPL tests its goodwill for impairment annually as of November 1 and whenever an event occurs or circumstances change in the interim that would more likely than not reduce the fair value of DPL below the carrying amount of its net assets. Factors that may result in an interim impairment test include, but are not limited to: a change in the identified reporting units; an adverse change in business conditions; an adverse regulatory action; or an impairment of DPL's long-lived assets. DPL concluded that an interim impairment test was not required during the nine months ended September 30, 2013.

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in DPL's gross revenues were $4 million for each of the three months ended September 30, 2013 and 2012, and $12 million for each of the nine months ended September 30, 2013 and 2012.

Reclassifications and Adjustments

Certain prior period amounts have been reclassified in order to conform to the current period presentation. The following adjustment has been recorded and is not considered material:

In the second quarter of 2012, DPL recorded an adjustment to correct an overstatement of unbilled revenue in its natural gas distribution business related to prior periods. The adjustment resulted in a decrease in Operating Revenue of $1 million for the nine months ended September 30, 2012.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Balance Sheet (ASC 210)

In December 2011, the FASB issued new disclosure requirements for financial assets and financial liabilities, such as derivatives, that are subject to contractual netting arrangements. The new disclosure requirements include information about the gross exposure of the instruments and the net exposure of the instruments under contractual netting arrangements, how the exposures are presented in the financial statements, and the terms and conditions of the contractual netting arrangements. DPL adopted the new guidance during the first quarter of 2013 and concluded it did not have a material impact on its financial statements.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Joint and Several Liability Arrangements (ASC 405)

In February 2013, the FASB issued new recognition and disclosure requirements for certain joint and several liability arrangements where the total amount of the obligation is fixed at the reporting date. For arrangements within the scope of this standard, DPL will be required to include in its liabilities the additional amounts it expects to pay on behalf of its co-obligors, if any. DPL will also be required to provide additional disclosures including the nature of the arrangements with its co-obligors, the total amounts outstanding under the arrangements between DPL and its co-obligors, the carrying value of the liability, and the nature and limitations of any recourse provisions that would enable recovery from other entities.

The new requirements would be effective retroactively beginning on January 1, 2014, with implementation required for prior periods if joint and several liability arrangement obligations exist as of January 1, 2014. DPL is evaluating the impact of this new guidance on its financial statements.

Income Taxes (ASC 740)

In July 2013, the FASB issued new guidance that will require the netting of certain unrecognized tax benefits against a deferred tax asset for a loss or other similar tax carryforward that would apply upon settlement of the uncertain tax position. The new requirements are effective prospectively beginning with DPL's March 31, 2014 financial statements for all unrecognized tax benefits existing at the adoption date. Retrospective implementation and early adoption of the guidance are permitted. DPL is evaluating the impact of this new guidance on its financial statements.

(5) SEGMENT INFORMATION

DPL operates its business as one regulated utility segment, which includes all of its services as described above.

(6) GOODWILL

DPL's goodwill balance of $8 million was unchanged during the nine months ended September 30, 2013. All of DPL's goodwill was generated by its acquisition of Conowingo Power Company in 1995.

DPL's annual impairment test as of November 1, 2012 indicated that goodwill was not impaired. For the nine months ended September 30, 2013, DPL concluded that there were no events requiring it to perform an interim goodwill impairment test. DPL will perform its next annual impairment test as of November 1, 2013.

(7) REGULATORY MATTERS

Rate Proceedings

Over the last several years, DPL has proposed in each of its jurisdictions the adoption of a mechanism to decouple retail distribution revenue from the amount of power delivered to retail customers. To date:

- A bill stabilization adjustment (BSA) was approved and implemented for electric service in Maryland.
- A modified fixed variable rate design (MFVRD) is under consideration by the DPSC for electric and natural gas service in Delaware.

Under the BSA, customer distribution rates are subject to adjustment (through a credit or surcharge mechanism), depending on whether actual distribution revenue per customer exceeds or falls short of the revenue-per-customer amount approved by the applicable public service commission. The MFVRD approved in concept in Delaware provides for a fixed customer charge (i.e., not tied to the customer's volumetric consumption of electricity or natural gas) to recover the utility's fixed costs, plus a reasonable rate of return. Although different from the BSA, DPL views the MFVRD as an appropriate distribution revenue decoupling mechanism.

Delaware

Gas Cost Rates

DPL makes an annual Gas Cost Rate (GCR) filing with the DPSC for the purpose of allowing DPL to recover natural gas procurement costs through customer rates. On August 28, 2013, DPL made its 2013 GCR filing. The rates proposed in the 2013 GCR filing would result in a GCR decrease of approximately 5.5%. On September 26, 2013, the DPSC issued an order authorizing DPL to place the new rates into effect on November 1, 2013, subject to refund and pending final DPSC approval.

Electric Distribution Base Rates

On March 22, 2013, DPL submitted an application with the DPSC to increase its electric distribution base rates. The filing seeks approval of an annual rate increase of approximately $39 million (as adjusted by DPL on September 20, 2013), based on a requested return on equity (ROE) of 10.25%. The requested rate increase seeks to recover expenses associated with DPL's ongoing efforts to maintain safe and reliable service. The DPSC suspended the full proposed increase and, as permitted by state law, DPL implemented an interim increase of $2.5 million on June 1, 2013, subject to refund and pending final DPSC approval. On October 8, 2013, the DPSC approved DPL's request to implement an additional interim increase of $25.1 million, effective on October 22, 2013, bringing the total interim rates in effect subject to refund to $27.6 million. A final DPSC decision is expected by the first quarter of 2014.

Forward Looking Rate Plan

On October 2, 2013, DPL filed a multi-year rate plan, referred to as the Forward Looking Rate Plan (FLRP). As proposed, the FLRP would establish electric distribution base rates to be increased annually over a four-year period, resulting in four annual DPL electric distribution rate increases, and the amount of the increase over that period would be approximately $56 million. While the proposed authorized ROE under the FLRP is 9.75%, the FLRP as proposed provides the opportunity to achieve estimated earned ROEs of 7.41% and 8.8% in years one and two, respectively, and 9.75% in both years three and four of the plan.

In addition, DPL proposes that as part of the FLRP, in order to provide a higher minimum required standard of reliability for DPL's customers, the reliability standards by which DPL's reliability is measured would be made more stringent in each year of the FLRP. In addition, DPL has offered to refund an annual aggregate of $500,000 to customers in each year of the FLRP that it fails to meet the proposed stricter minimum reliability standards.

On October 22, 2013, the DPSC opened a docket for the purpose of reviewing the details of the FLRP, but stated that the electric distribution base rate case discussed above should be concluded before the FLRP is addressed. DPL expects that the FLRP will be updated and re-filed at the conclusion of the electric distribution base rate case. A schedule for the FLRP docket has not yet been established.

Gas Distribution Base Rates

On December 7, 2012, DPL submitted an application with the DPSC to increase its natural gas distribution base rates. The filing seeks approval of an annual rate increase of approximately $12.0 million (as adjusted by DPL on July 15, 2013), based on a requested ROE of 10.25%. The requested rate increase is for the purposes of recovering expenses associated with DPL's ongoing efforts to maintain safe and reliable service and to provide enhanced customer service technology. The DPSC suspended the full proposed increase and, as permitted by state law, DPL implemented an interim increase of $2.5 million on February 5, 2013, subject to refund and pending final DPSC approval. On July 2, 2013, the DPSC approved DPL's request to implement an additional interim increase of $8 million, effective on July 7, 2013. On October 22, 2013, the DPSC approved a settlement entered into on August 27, 2013 by the DPSC Staff, the Delaware Division of the Public Advocate and DPL, which provides for an annual rate increase of $6.8 million. The excess amount collected when the interim increases were in effect will be returned to customers. While the approved settlement provides that no understanding was reached concerning the appropriate ROE, for reporting purposes and for calculating the AFUDC, construction work in progress (CWIP), regulatory asset carrying costs and other accounting metrics, the rate of 9.75% should be used. The new rates became effective on November 1, 2013.

The approved settlement also provides for a phase-in of the recovery of the deferred costs associated with DPL's deployment of the interface management unit (IMU), which allows for the remote reading of the gas meter portion of its advanced metering infrastructure (AMI), through base rates over a two-year period, assuming specific milestones are met and pursuant to the following schedule: 50% of the IMU portion of DPL's AMI will be put into rates on May 1, 2014, and the remainder will be put into rates on March 1, 2015. DPL also agreed that its next natural gas distribution base rate application may be filed with the DPSC no earlier than January 1, 2015.

Maryland

Electric Distribution Base Rates

On March 29, 2013, DPL submitted an application with the Maryland Public Service Commission (MPSC) to increase its electric distribution base rates by approximately $22.8 million, based on a requested ROE of 10.25%. The requested rate increase was for the purpose of recovering reliability enhancements to serve Maryland customers. DPL also proposed a three-year Grid Resiliency Charge rider for recovery of costs totaling approximately $10.2 million associated with its plan to accelerate investments in electric distribution infrastructure in a condensed timeframe. Acceleration of resiliency improvements was one of several recommendations included in a September 2012 report from Maryland's Grid Resiliency Task Force (as discussed below under "Resiliency Task Force"). Specific projects under DPL's Grid Resiliency Charge plan included accelerating its tree-trimming cycle and upgrading five additional feeders per year for two years. In addition, DPL proposed a reliability performance-based mechanism that would allow DPL to earn up to $500,000 as an incentive for meeting enhanced reliability goals in 2015, but provided for a credit to customers of up to $500,000 in total if DPL does not meet at least the minimum reliability performance targets. DPL requested that any credits or charges would flow through the proposed Grid Resiliency Charge rider.

On August 30, 2013, the MPSC issued a final order approving a settlement among DPL, the MPSC staff and the Maryland Office of People's Counsel. The approved settlement provides for an annual rate increase of approximately $15 million. While the settlement does not specify an overall ROE, the parties did agree that the ROE for purposes of calculating the AFUDC and regulatory asset carrying costs would be 9.81%. The approved settlement also provides for (i) recovery of storm restoration costs incurred as a result of recent major storm events, including the derecho storm in June 2012 and Hurricane Sandy in October 2012, by amortizing the related deferred operation and maintenance expenses of approximately $6 million over a five-year period with the unamortized balance included in rate base, and (ii) a Grid Resiliency Charge for recovery of costs totaling approximately $4.2 million associated with DPL's proposed plan to accelerate investments related to certain priority feeders, provided that DPL provides additional information to the MPSC before implementing the surcharge related to performance objectives, milestones and costs, and makes annual filings with the MPSC thereafter concerning this project, which will permit the MPSC to establish the applicable Grid Resiliency Charge rider for the following year. The approved settlement does not provide for approval of a portion of the Grid Resiliency Charge related to the proposed acceleration of the tree-trimming cycle, or DPL's proposed reliability performance-based mechanism. The new rates became effective on September 15, 2013.

Federal Energy Regulatory Commission

On October 17, 2013, the Federal Energy Regulatory Commission (FERC) issued a ruling on challenges filed by the Delaware Electric Municipal Corporation to DPL's 2011 and 2012 annual formula rate updates. In 2006, FERC approved a formula rate for DPL that is incorporated into the PJM Interconnection, LLC (PJM) tariff. The formula rate establishes the treatment of costs and revenues and the resulting rates for DPL. Pursuant to the protocols approved by FERC and after a period of discovery, interested parties have an opportunity to file challenges regarding the application of the formula rate. The FERC order sets various issues in this proceeding for hearing, including challenges regarding formula rate inputs, deferred income items, prepayments of estimated income taxes, rate base reductions, various administrative and general expenses and the inclusion in rate base of CWIP related to the Mid-Atlantic Power Pathway (MAPP) project (which has been abandoned). Settlement discussions began in this matter on November 5, 2013 before an administrative law judge at FERC.

MPSC New Generation Contract Requirement

In September 2009, the MPSC initiated an investigation into whether Maryland electric distribution companies (EDCs) should be required to enter into long-term contracts with entities that construct, acquire or lease, and operate, new electric generation facilities in Maryland.

In April 2012, the MPSC issued an order determining that there is a need for one new power plant in the range of 650 to 700 MW beginning in 2015. The order requires DPL, its affiliate Potomac Electric Power Company (Pepco), and Baltimore Gas and Electric Company (BGE) (collectively, the Contract EDCs) to negotiate and enter into a contract with the winning bidder of a competitive bidding process in amounts proportional to their relative Standard Offer Service (SOS) loads. Under the contract, the winning bidder will construct a 661 MW natural gas-fired combined cycle generation plant in Waldorf, Maryland, with an expected commercial operation date of June 1, 2015. The order acknowledged the Contract EDCs' concerns about the requirements of the contract and directed them to negotiate with the winning bidder and submit any proposed changes in the contract to the MPSC for approval. The order further specified that the Contract EDCs will recover the associated costs through surcharges on their respective SOS customers.

In April 2012, a group of generating companies operating in the PJM region filed a complaint in the U.S. District Court for the District of Maryland challenging the MPSC's order on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. In May 2012, the Contract EDCs and other parties filed notices of appeal in circuit courts in Maryland requesting judicial review of the MPSC's order. These circuit court appeals were consolidated in the Circuit Court for Baltimore City.

On April 16, 2013, the MPSC issued an order approving a final form of the contract and directing the Contract EDCs to enter into the contract with the winning bidder in amounts proportional to their relative SOS loads. On June 4, 2013, DPL entered into the contract in accordance with the terms of the MPSC's order; however, under the contract's own terms, it will not become effective, if at all, until all legal proceedings related to the contract and the actions of the MPSC in the related proceeding have been resolved.

On September 30, 2013, the U.S. District Court for the District of Maryland issued a ruling that the MPSC's April 2012 order violated the Supremacy Clause of the U.S. Constitution by attempting to regulate wholesale prices. In contrast, on October 1, 2013, the Maryland Circuit Court for Baltimore City upheld the MPSC's orders requiring the Contract EDCs to enter into the contracts.

On October 24, 2013, the Federal district court issued an order ruling that the contracts are illegal and unenforceable. This Federal district court order and its associated ruling could impact the state circuit court appeal, to which the Contract EDCs are parties, although such impact, if any, cannot be determined at this time. DPL expects the Federal district court decision to be appealed. The Contract EDCs also will likely appeal the state court decision to the Maryland Court of Special Appeals.

Assuming the contract, as currently written, were to become effective by the expected commercial operation date of June 1, 2015, DPL continues to believe that it may be required to account for its proportional share of the contract as a derivative instrument at fair value with an offsetting regulatory asset because they would recover any payments under the contract from SOS customers. In such event, DPL estimates that it would be required to record an aggregate derivative liability ranging from $15 million to $20 million, with an offsetting regulatory asset in a like amount. This estimated range and the related assumptions may change prior to the time that the contract becomes effective, if at all. DPL has concluded that any accounting for this contract would not be required until all legal proceedings related to the contract and the actions of the MPSC in the related proceeding have been resolved.

DPL is evaluating these proceedings to determine (i) the extent of the negative effect that the contract for new generation may have on its credit metrics, as calculated by independent rating agencies that evaluate and rate DPL and its debt issuances, (ii) the effect on DPL's ability to recover their associated costs of the contract for new generation if a significant number of SOS customers elect to buy their energy from alternative energy suppliers, and (iii) the effect of the contract on the financial condition, results of operations and cash flows of DPL.

Resiliency Task Force

In July 2012, the Maryland governor signed an Executive Order directing his energy advisor, in collaboration with certain state agencies, to solicit input and recommendations from experts on how to improve the resiliency and reliability of the electric distribution system in Maryland. The resulting Grid Resiliency Task Force issued its report in September 2012, in which it made 11 recommendations. The governor forwarded the report to the MPSC in October 2012, urging the MPSC to quickly implement the first four recommendations: (i) strengthen existing reliability and storm restoration regulations; (ii) accelerate the investment necessary to meet the enhanced metrics; (iii) allow surcharge recovery for the accelerated investment; and (iv) implement clearly defined performance metrics into the traditional ratemaking scheme. DPL's electric distribution base rate case filed with the MPSC on March 29, 2013 attempted to address the Grid Resiliency Task Force recommendations. In August 2013, the MPSC issued an order in the DPL Maryland electric distribution base rate case that only partially approved the proposed Grid Resiliency Charge. See "Rate Proceedings – Maryland – Electric Distribution Base Rates" above for more information about this base rate case.

MAPP Project

On August 24, 2012, the board of PJM terminated the Mid-Atlantic Power Pathway (MAPP) project and removed it from PJM's regional transmission expansion plan. PHI had been directed to construct the MAPP project, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region's transmission system. In December 2012, DPL submitted a filing to FERC seeking recovery of $38 million of abandoned MAPP costs over a five-year recovery period. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

Various protests were submitted in response to DPL's December 2012 filing, arguing, among other things, that FERC should disallow a portion of the rate of return involving an incentive adder that would be applied to the abandoned costs, and requesting a hearing on various issues such as the amount of the ROE and the prudence of the costs. On February 28, 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of DPL, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs. FERC reduced the ROE applicable to the abandoned costs from the previously approved 12.8% incentive ROE to 10.8% by disallowing 200 basis points of ROE adders. FERC also denied recovery of 50% (calculated by DPL to be $1 million) of the prudently incurred abandoned costs prior to November 1, 2008, the date of FERC's MAPP incentive order. DPL believes that the February 2013 FERC order is not consistent with prior precedent and is vigorously pursuing its rights to recover all prudently incurred abandoned costs associated with the MAPP project, as well as the full ROE previously approved by FERC. On April 1, 2013, PHI filed a rehearing request on behalf of DPL of the February 28, 2013 FERC order challenging the reduction of the ROE applicable to the abandoned costs, as well as the denial of 50% of the costs incurred prior to November 1, 2008. On that same date, a group of public advocates from Maryland, Delaware, New Jersey, Virginia, West Virginia and Pennsylvania also filed a rehearing request challenging the 10.8% ROE authorized in FERC's order, arguing that DPL is not entitled to any rate of return on the abandoned costs and that FERC improperly failed to set the ROE for hearing. DPL is currently engaged in settlement negotiations in this matter; however, DPL cannot predict when a final FERC decision in this proceeding will be issued.

As of September 30, 2013, DPL had a regulatory asset related to the MAPP abandoned costs of $32 million, representing the original filing amount of approximately $38 million of abandoned costs referred to above less: (i) approximately $1 million of disallowed costs written off in 2013; and (ii) $5 million of amortization expense recorded in 2013. The regulatory asset balance includes the costs of land, land rights, engineering and design, environmental services, and project management and administration. DPL intends to reduce further the amount of the regulatory asset by any amounts recovered from the sale or alternative use of the land.

Transmission ROE Challenge

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Electric Municipal Corporation, Inc., filed a joint complaint with FERC against DPL, Pepco, and Atlantic City Electric Company (ACE), an affiliate of DPL, as well as BGE. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that DPL provides. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for DPL is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. DPL believes the allegations in this complaint are without merit and is vigorously contesting it. On April 3, 2013, DPL filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable.

(8) PENSION AND OTHER POSTRETIREMENT BENEFITS

DPL accounts for its participation in its parent's single-employer plans, Pepco Holdings' non-contributory retirement plan (the PHI Retirement Plan) and the Pepco Holdings, Inc. Welfare Plan for Retirees, as participation in multiemployer plans. PHI's pension and other postretirement net periodic benefit cost for the three months ended September 30, 2013 and 2012, before intercompany allocations from the PHI Service Company, were $20 million and $28 million, respectively. DPL's allocated share was $4 million and $6 million for the three months ended September 30, 2013 and 2012, respectively. PHI's pension and other postretirement net periodic benefit cost for the nine months ended September 30, 2013 and 2012, before intercompany allocations from the PHI Service Company, were $74 million and $84 million, respectively. DPL's allocated share of the net periodic benefit cost was $14 million and $18 million for the nine months ended September 30, 2013 and 2012, respectively.

In the first quarter of 2013, DPL made a discretionary tax-deductible contribution to the PHI Retirement Plan of $10 million. In the first quarter of 2012, DPL made a discretionary tax-deductible contribution to the PHI Retirement Plan of $85 million.

Other Postretirement Benefit Plan Amendment

During 2013, PHI approved two amendments to its other postretirement benefits plan. These amendments impacted the retiree medical plan and the retiree life insurance benefits, and will be effective on January 1, 2014. As a result of the amendments, which were cumulatively significant, PHI remeasured its projected benefit obligation for other postretirement benefits as of July 1, 2013. The remeasurement is expected to result in a $3 million reduction in DPL's net periodic benefit cost for other postretirement benefits during 2013. Approximately 30% of net periodic other postretirement benefit costs are capitalized.

(9) DEBT

Credit Facility

PHI, Pepco, DPL and ACE maintain an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. On August 1, 2011, PHI, Pepco, DPL and ACE entered into an amended and restated credit agreement which, on August 2, 2012, was amended to extend the term of the credit facility to August 1, 2017 and to amend the pricing schedule to decrease certain fees and interest rates payable to the lenders under the facility. On June 6, 2013, as permitted under the existing terms of the credit agreement, PHI, Pepco, DPL and ACE provided to the agent and lenders under the credit agreement, a notice requesting a one-year extension of the credit facility termination date. The request was approved and the new termination date is August 1, 2018. All of the terms and conditions as well as pricing remain the same.

The aggregate borrowing limit under the amended and restated credit facility is $1.5 billion, all or any portion of which may be used to obtain loans and up to $500 million of which may be used to obtain letters of credit. The facility also includes a swingline loan sub-facility, pursuant to which each company may make same day borrowings in an aggregate amount not to exceed 10% of the total amount of the facility. Any swingline loan must be repaid by the borrower within fourteen days of receipt. The credit sublimit is $750 million for PHI and $250 million for each of Pepco, DPL and ACE. The sublimits may be increased or decreased by the individual borrower during the term of the facility, except that (i) the sum of all of the borrower sublimits following any such increase or decrease must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by (a) PHI may not exceed $1.25 billion, and (b) each of Pepco, DPL or ACE may not exceed the lesser of $500 million or the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the sublimit reallocations may not exceed eight per year during the term of the facility.

The interest rate payable by each company on utilized funds is, at the borrowing company's election, (i) the greater of the prevailing prime rate, the federal funds effective rate plus 0.5% and the one month London Interbank Offered Rate plus 1.0%, or (ii) the prevailing Eurodollar rate, plus a margin that varies according to the credit rating of the borrower.

In order for a borrower to use the facility, certain representations and warranties must be true and correct, and the borrower must be in compliance with specified financial and other covenants, including (i) the requirement that each borrowing company maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the credit agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) with certain exceptions, a restriction on sales or other dispositions of assets, and (iii) a restriction on the incurrence of liens on the assets of a borrower or any of its significant subsidiaries other than permitted liens. The credit agreement contains certain covenants and other customary agreements and requirements that, if not complied with, could result in an event of default and the acceleration of repayment obligations of one or more of the borrowers thereunder. Each of the borrowers was in compliance with all covenants under this facility as of September 30, 2013.

The absence of a material adverse change in PHI's business, property, results of operations or financial condition is not a condition to the availability of credit under the credit agreement. The credit agreement does not include any rating triggers.

As of September 30, 2013 and December 31, 2012, the amount of cash plus borrowing capacity under the credit facility available to meet the liquidity needs of PHI's utility subsidiaries in the aggregate was $471 million and $477 million, respectively. DPL's borrowing capacity under the credit facility at any given time depends on the amount of the subsidiary borrowing capacity being utilized by Pepco and ACE and the portion of the total capacity being used by PHI.

Commercial Paper

DPL maintains an on-going commercial paper program to address its short-term liquidity needs. As of September 30, 2013, the maximum capacity available under the program was $500 million, subject to available borrowing capacity under the credit facility.

DPL had $150 million of commercial paper outstanding at September 30, 2013. The weighted average interest rate for commercial paper issued by DPL during the nine months ended September 30, 2013 was 0.29% and the weighted average maturity of all commercial paper issued by DPL during the nine months ended September 30, 2013 was three days.

(10) INCOME TAXES

A reconciliation of DPL's effective income tax rates is as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2013		2012		2013		2012	
	(millions of dollars)							
Income tax at Federal statutory rate	$ 13	35.0%	$ 12	35.0%	$ 35	35.0%	$ 32	35.0%
Increases (decreases) resulting from:								
State income taxes, net of Federal effect	2	5.4%	2	6.1%	5	5.0%	5	5.6%
Adjustments to prior year taxes	—	—	(2)	(6.1)%	—	—	(2)	(2.2)%
Change in estimates and interest related to uncertain and effectively settled tax positions	—	—	—	—	(1)	(1.0)%	—	—
Depreciation	—	—	(1)	(3.0)%	—	—	(1)	(1.1)%
Other, net	(1)	(2.6)%	—	1.3%	—	—	—	0.5%
Income tax expense	$ 14	37.8%	$ 11	33.3%	$ 39	39.0%	$ 34	37.8%

Three Months Ended September 30, 2013 and 2012

DPL's effective tax rates for the three months ended September 30, 2013 and 2012 were 37.8% and 33.3%, respectively. The increase in the effective tax rate primarily resulted from adjustments to prior year taxes and tax benefits related to depreciation that were recorded during the three months ended September 30, 2012.

Nine Months Ended September 30, 2013 and 2012

DPL's effective tax rates for the nine months ended September 30, 2013 and 2012 were 39.0% and 37.8%, respectively. The increase in the effective tax rate primarily resulted from adjustments to prior year taxes recorded during the nine months ended September 30, 2012.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which DPL is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. As a result of the court's ruling in this case, PHI determined in the first quarter of 2013 that it could no longer support its current assessment with respect to the likely outcome of tax positions associated with its cross-border energy lease investments held by its wholly-owned subsidiary Potomac Capital Investment Corporation, and PHI recorded a charge of $377 million (after-tax) in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $54 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in DPL recording a $1 million interest benefit in the first quarter of 2013.

Final IRS Regulations on Repair of Tangible Property

In September 2013, the IRS issued final regulations on expense versus capitalization of repairs with respect to tangible personal property. The regulations are effective for tax years beginning on or after January 1, 2014, and provide an option to early adopt the final regulations for tax years beginning on or after January 1, 2012. It is expected that the IRS will issue revenue procedures that will describe how taxpayers may implement the final regulations. The final repair regulations retain the operative rule that the Unit of Property for network assets is determined by the taxpayer's particular facts and circumstances except as provided in published guidance. In 2012, with the filing of its 2011 tax return, PHI filed a request for an automatic change in accounting method related to repairs of its network assets in accordance with IRS Revenue Procedure 2011-43. DPL does not expect the effects of the final regulations to be significant and will continue to evaluate the impact of the new guidance on its financial statements.

(11) DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

DPL uses derivative instruments in the form of swaps and over-the-counter options primarily to reduce natural gas commodity price volatility and limit its customers' exposure to increases in the market price of natural gas under a hedging program approved by the DPSC. DPL uses these derivatives to manage the commodity price risk associated with its physical natural gas purchase contracts. The natural gas purchase contracts qualify as normal purchases, which are not required to be recorded in the financial statements until settled. All premiums paid and other transaction costs incurred as part of DPL's natural gas hedging activity, in addition to all gains and losses related to hedging activities, are deferred under FASB guidance on regulated operations (ASC 980) until recovered from its customers through a fuel adjustment clause approved by the DPSC.

The tables below identify the balance sheet location and fair values of derivative instruments as of September 30, 2013 and December 31, 2012:

	As of September 30, 2013				
Balance Sheet Caption	**Derivatives Designated as Hedging Instruments**	**Other Derivative Instruments**	**Gross Derivative Instruments**	**Effects of Cash Collateral and Netting**	**Net Derivative Instruments**
			(millions of dollars)		
Derivative liabilities (current liabilities)	$ —	$ (1)	$ (1)	$ 1	$ —
Net Derivative liability	$ —	$ (1)	$ (1)	$ 1	$ —

	As of December 31, 2012				
Balance Sheet Caption	**Derivatives Designated as Hedging Instruments**	**Other Derivative Instruments**	**Gross Derivative Instruments**	**Effects of Cash Collateral and Netting**	**Net Derivative Instruments**
			(millions of dollars)		
Derivative liabilities (current liabilities)	$ —	$ (4)	$ (4)	$ —	$ (4)
Net Derivative liability	$ —	$ (4)	$ (4)	$ —	$ (4)

Under FASB guidance on the offsetting of balance sheet accounts (ASC 210-20), DPL offsets the fair value amounts recognized for derivative instruments and fair value amounts recognized for related collateral positions executed with the same counterparty under master netting agreements. All derivative assets and liabilities available to be offset under master netting arrangements were netted as of September 30, 2013 and December 31, 2012. The amount of cash collateral that was offset against these derivative positions is as follows:

	September 30, 2013	**December 31, 2012**
	(millions of dollars)	
Cash collateral pledged to counterparties with the right to reclaim (a)	$ 1	$ —

(a) Includes cash deposits on commodity brokerage accounts.

As of September 30, 2013 and December 31, 2012, all DPL cash collateral pledged related to derivative instruments accounted for at fair value was entitled to be offset under master netting agreements.

Other Derivative Activity

DPL holds certain derivatives that are not in hedge accounting relationships and are not designated as normal purchases or normal sales. These derivatives are recorded at fair value on the balance sheets with the gain or loss for changes in the fair value recorded in income. In accordance with FASB guidance on regulated operations, offsetting regulatory liabilities or regulatory assets are recorded on the balance sheets and the recognition of the derivative gain or loss is deferred because of the DPSC-approved fuel adjustment clause. For the three and nine months ended September 30, 2013 and 2012, the net unrealized derivative gains and losses arising during the period that were deferred as regulatory liabilities and regulatory assets and the net realized losses recognized in the statements of income (through Purchased Energy and Gas Purchased expense) that were also deferred as regulatory assets are provided in the table below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(millions of dollars)			
Net unrealized gain (loss) arising during the period	$ —	$ 2	$ —	$ (2)
Net realized losses recognized during the period	—	(2)	(3)	(13)

As of September 30, 2013 and December 31, 2012, DPL had the following net outstanding natural gas commodity forward contracts that did not qualify for hedge accounting:

	September 30, 2013		December 31, 2012	
Commodity	Quantity	Net Position	Quantity	Net Position
Natural gas (one Million British Thermal Units)	3,767,500	Long	3,838,000	Long

Contingent Credit Risk Features

The primary contracts used by DPL for derivative transactions are entered into under the International Swaps and Derivatives Association Master Agreement (ISDA) or similar agreements that closely mirror the principal credit provisions of the ISDA. The ISDAs include a Credit Support Annex (CSA) that governs the mutual posting and administration of collateral security. The failure of a party to comply with an obligation under the CSA, including an obligation to transfer collateral security when due or the failure to maintain any required credit support, constitutes an event of default under the ISDA for which the other party may declare an early termination and liquidation of all transactions entered into under the ISDA, including foreclosure against any collateral security. In addition, some of the ISDAs have cross default provisions under which a default by a party under another commodity or derivative contract, or the breach by a party of another borrowing obligation in excess of a specified threshold, is a breach under the ISDA.

Under the ISDA or similar agreements, the parties establish a dollar threshold of unsecured credit for each party in excess of which the party would be required to post collateral to secure its obligations to the other party. The amount of the unsecured credit threshold varies according to the senior, unsecured debt rating of the respective parties or that of a guarantor of the party's obligations. The fair values of all transactions between the parties are netted under the master netting provisions. Transactions may include derivatives accounted for on-balance sheet as well as normal purchases and normal sales that are accounted for off-balance sheet. If the aggregate fair value of the transactions in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. The obligations of DPL are stand-alone obligations without the guaranty of PHI. If DPL's debt rating were to fall below "investment grade," the unsecured credit threshold would typically be set at zero and collateral would be required for the entire net loss position. Exchange-traded contracts are required to be fully collateralized without regard to the credit rating of the holder.

The gross fair values of DPL's derivative liabilities with credit-risk-related contingent features as of September 30, 2013 and December 31, 2012, were zero and $4 million, respectively. As of those dates, DPL had posted no cash collateral in the normal course of business against its gross derivative liabilities, resulting in net liabilities of zero and $4 million, respectively. If DPL's debt ratings had been downgraded below investment grade as of September 30, 2013 and December 31, 2012, DPL's net settlement amounts would have been approximately zero and $2 million, respectively, and DPL would have been required to post collateral with the counterparties of approximately zero and $2 million, respectively. The net settlement and additional collateral amounts reflect the effect of offsetting transactions under master netting agreements.

DPL's primary source for posting cash collateral or letters of credit is PHI's credit facility. As of September 30, 2013 and December 31, 2012, the aggregate amount of cash plus borrowing capacity under the credit facility available to meet the liquidity needs of PHI's utility subsidiaries was $471 million and $477 million, respectively.

(12) FAIR VALUE DISCLOSURES

Financial Instruments Measured at Fair Value on a Recurring Basis

DPL applies FASB guidance on fair value measurement and disclosures (ASC 820) that established a framework for measuring fair value and expanded disclosures about fair value measurements. As defined in the guidance, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). DPL utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. Accordingly, DPL utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1) and the lowest priority to unobservable inputs (level 3).

The following tables set forth, by level within the fair value hierarchy, DPL's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2013 and December 31, 2012. As required by the guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. DPL's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair Value Measurements at September 30, 2013			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
	(millions of dollars)			
ASSETS				
Executive deferred compensation plan assets				
Money market funds	$ 1	$ 1	$ —	$ —
Life insurance contracts	1	—	—	1
	$ 2	$ 1	$ —	$ 1
LIABILITIES				
Derivative instruments (b)				
Natural gas (c)	$ 1	$ 1	$ —	$ —
Executive deferred compensation plan liabilities				
Life insurance contracts	1	—	1	—
	$ 2	$ 1	$ 1	$ —

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the nine months ended September 30, 2013.
(b) The fair value of derivative liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents natural gas swaps purchased by DPL as part of a natural gas hedging program approved by the DPSC.

	Fair Value Measurements at December 31, 2012			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
	(millions of dollars)			
ASSETS				
Executive deferred compensation plan assets				
Money market funds	$ 2	$ 2	$ —	$ —
Life insurance contracts	1	—	—	1
	$ 3	$ 2	$ —	$ 1
LIABILITIES				
Derivative instruments (b)				
Natural gas (c)	$ 4	$ —	$ —	$ 4
	$ 4	$ —	$ —	$ 4

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2012.
(b) The fair value of derivative liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents natural gas options purchased by DPL as part of a natural gas hedging program approved by the DPSC.

DPL classifies its fair value balances in the fair value hierarchy based on the observability of the inputs used in the fair value calculation as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis, such as the New York Mercantile Exchange (NYMEX).

Level 2 – Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using broker quotes in liquid markets and other observable data. Level 2 also includes those financial instruments that are valued using methodologies that have been corroborated by observable market data through correlation or by other means. Significant assumptions are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 2 executive deferred compensation plan liabilities associated with the life insurance policies represent a deferred compensation obligation, the value of which is tracked via underlying insurance sub-accounts. The sub-accounts are designed to mirror existing mutual funds and money market funds that are observable and actively traded.

Level 3 – Pricing inputs that are significant and generally less observable than those from objective sources. Level 3 includes those financial instruments that are valued using models or other valuation methodologies.

Derivative instruments categorized as level 3 as of December 31, 2012, represent natural gas options used by DPL as part of a natural gas hedging program approved by the DPSC. DPL applies a Black-Scholes model to value its options with inputs, such as forward price curves, contract prices, contract volumes, the risk-free rate and implied volatility factors that are based on a range of historical NYMEX option prices. DPL maintains valuation policies and procedures and reviews the validity and relevance of the inputs used to estimate the fair value of its options. As of September 30, 2013, all of these contracts classified as level 3 derivative instruments have settled.

The table below summarizes the primary unobservable input used to determine the fair value of DPL's level 3 instruments and the range of values that could be used for the input as of December 31, 2012:

Type of Instrument	**Fair Value at December 31, 2012** *(millions of dollars)*	**Valuation Technique**	**Unobservable Input**	**Range**
Natural gas options	$ (4)	Option model	Volatility factor	1.57 – 2.00

DPL used values within this range as part of its fair value estimates. A significant change in the unobservable input within this range would have an insignificant impact on the reported fair value as of December 31, 2012.

Executive deferred compensation plan assets include certain life insurance policies that are valued using the cash surrender value of the policies, net of loans against those policies. The cash surrender values do not represent a quoted price in an active market; therefore, those inputs are unobservable and the policies are categorized as level 3. Cash surrender values are provided by third parties and reviewed by DPL for reasonableness.

Reconciliations of the beginning and ending balances of DPL's fair value measurements using significant unobservable inputs (level 3) for the nine months ended September 30, 2013 and 2012, are shown below:

	Nine Months Ended September 30, 2013	
	Natural Gas	Life Insurance Contracts
	(millions of dollars)	
Beginning balance as of January 1	$ (4)	$ 1
Total gains (losses) (realized and unrealized):		
Included in income	—	—
Included in accumulated other comprehensive loss	—	—
Included in regulatory assets	—	—
Purchases	—	—
Issuances	—	—
Settlements	4	—
Transfers in (out) of level 3	—	—
Ending balance as of September 30	$ —	$ 1

	Nine Months Ended September 30, 2012	
	Natural Gas	Life Insurance Contracts
	(millions of dollars)	
Beginning balance as of January 1	$ (15)	$ 1
Total gains (losses) (realized and unrealized):		
Included in income	—	—
Included in accumulated other comprehensive loss	—	—
Included in regulatory assets	(2)	—
Purchases	—	—
Issuances	—	—
Settlements	10	—
Transfers in (out) of level 3	—	—
Ending balance as of September 30	$ (7)	$ 1

Other Financial Instruments

The estimated fair values of DPL's debt instruments that are measured at amortized cost in DPL's financial statements and the associated level of the estimates within the fair value hierarchy as of September 30, 2013 and December 31, 2012 are shown in the tables below. As required by the fair value measurement guidance, debt instruments are classified in their entirety within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. DPL's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, which may affect the valuation of fair value debt instruments and their placement within the fair value hierarchy levels.

The fair value of Long-term debt categorized as level 2 is based on a blend of quoted prices for the debt and quoted prices for similar debt on the measurement date. The blend places more weight on current pricing information when determining the final fair value measurement. The fair value information is provided by brokers and DPL reviews the methodologies and results.

The fair value of Long-term debt categorized as level 3 is based on a discounted cash flow methodology using observable inputs, such as the U.S. Treasury yield, and unobservable inputs, such as credit spreads, because quoted prices for the debt or similar debt in active markets were insufficient.

	Fair Value Measurements at September 30, 2013			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(millions of dollars)			
LIABILITIES				
Debt instruments				
Long-term debt (a)	$928	$ —	$ 817	$ 111
	$928	$ —	$ 817	$ 111

(a) The carrying amount for Long-term debt is $917 million as of September 30, 2013.

	Fair Value Measurements at December 31, 2012			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(millions of dollars)			
LIABILITIES				
Debt instruments				
Long-term debt (a)	$990	$ —	$ 877	$ 113
	$990	$ —	$ 877	$ 113

(a) The carrying amount for Long-term debt is $917 million as of December 31, 2012.

The carrying amounts of all other financial instruments in the accompanying consolidated financial statements approximate fair value.

(13) COMMITMENTS AND CONTINGENCIES

Environmental Matters

DPL is subject to regulation by various federal, regional, state, and local authorities with respect to the environmental effects of its operations, including air and water quality control, solid and hazardous waste disposal, and limitations on land use. Although penalties assessed for violations of environmental laws and regulations are not recoverable from DPL's customers, environmental clean-up costs incurred by DPL generally are included in its cost of service for ratemaking purposes. The total accrued liabilities for the environmental contingencies of DPL described below at September 30, 2013 are summarized as follows:

	Transmission and Distribution	Legacy Generation - Regulated	Other	Total
		(millions of dollars)		
Beginning balance as of January 1	$ 1	$ 3	$ 2	$ 6
Accruals	—	—	1	1
Payments	—	1	2	3
Ending balance as of September 30	1	2	1	4
Less amounts in Other Current Liabilities	1	1	—	2
Amounts in Other Deferred Credits	$ —	$ 1	$ 1	$ 2

Ward Transformer Site

In April 2009, a group of potentially responsible parties (PRPs) with respect to the Ward Transformer site in Raleigh, North Carolina, filed a complaint in the U.S. District Court for the Eastern District of North Carolina, alleging cost recovery and/or contribution claims against a number of entities, including DPL, based on its alleged sale of transformers to Ward Transformer, with respect to past and future response costs incurred by the PRP group in performing a removal action at the site. In a March 2010 order, the court denied the defendants' motion to dismiss. The litigation is moving forward with certain "test case" defendants (not including DPL) filing summary judgment motions regarding liability. The case has been stayed as to the remaining defendants pending rulings upon the test cases. In a January 31, 2013 order, the district court granted summary judgment for the test case defendant whom plaintiffs alleged was liable based on its sale of transformers to Ward Transformer. The district court's order, which plaintiffs have appealed to the U.S. Court of Appeals for the Fourth Circuit, addresses only the liability of the test case defendant. DPL has concluded that a loss is reasonably possible with respect to this matter, but was unable to estimate an amount or range of reasonably possible losses to which it may be exposed. DPL does not believe that it had extensive business transactions, if any, with the Ward Transformer site.

Indian River Oil Release

In 2001, DPL entered into a consent agreement with the Delaware Department of Natural Resources and Environmental Control for remediation, site restoration, natural resource damage compensatory projects and other costs associated with environmental contamination resulting from an oil release at the Indian River generating facility, which was sold in June 2001. The amount of remediation costs accrued for this matter is included in the table above in the column entitled "Legacy Generation – Regulated."

Metal Bank Site

In March 2013, the National Oceanic and Atmospheric Administration (NOAA) contacted DPL on behalf of itself and other federal and state trustees to request that Pepco and DPL execute a tolling agreement to facilitate settlement negotiations concerning natural resource damages allegedly caused by releases of hazardous substances, including polychlorinated biphenyls, at the Metal Bank Superfund Site located in Philadelphia, Pennsylvania. DPL has executed the tolling agreement and will participate in settlement discussions with the NOAA, the trustees and other PRPs.

The amount accrued for this matter is included in the table above in the column entitled "Transmission and Distribution."

(14) RELATED PARTY TRANSACTIONS

PHI Service Company provides various administrative and professional services to PHI and its regulated and unregulated subsidiaries, including DPL. The cost of these services is allocated in accordance with cost allocation methodologies set forth in the service agreement using a variety of factors, including the subsidiaries' share of employees, operating expenses, assets and other cost methods. These intercompany transactions are eliminated by PHI in consolidation and no profit results from these transactions at PHI. PHI Service Company costs directly charged or allocated to DPL for the three months ended September 30, 2013 and 2012 were approximately $38 million and $40 million, respectively. PHI Service Company costs directly charged or allocated to DPL for the nine months ended September 30, 2013 and 2012 were approximately $115 million and $114 million, respectively.

In addition to the PHI Service Company charges described above, DPL's financial statements include the following related party transactions in its statements of income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(millions of dollars)			
Intercompany lease transactions (a)	$ 1	$ 1	$ 3	$ 3

(a) Included in Electric revenue.

As of September 30, 2013 and December 31, 2012, DPL had the following balances on its balance sheets due to related parties:

	September 30, 2013	December 31, 2012
	(millions of dollars)	
Payable to Related Party (current) (a)		
PHI Service Company	$ (21)	$ (19)
Other	—	(1)
Total	$ (21)	$ (20)

(a) Included in Accounts Payable Due to Associated Companies.

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
	(millions of dollars)			
Operating Revenue	$ 396	$ 413	$ 944	$ 939
Operating Expenses				
Purchased energy	198	226	509	555
Other operation and maintenance	58	66	177	178
Depreciation and amortization	38	37	101	92
Other taxes	5	6	11	14
Deferred electric service costs	42	29	39	(6)
Total Operating Expenses	341	364	837	833
Operating Income	55	49	107	106
Other Income (Expenses)				
Interest expense	(17)	(17)	(52)	(52)
Other income	—	1	—	3
Total Other Expenses	(17)	(16)	(52)	(49)
Income Before Income Tax Expense	38	33	55	57
Income Tax Expense	13	13	14	21
Net Income	$ 25	$ 20	$ 41	$ 36

The accompanying Notes are an integral part of these Consolidated Financial Statements.

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2013	December 31, 2012
	(millions of dollars)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 6	$ 6
Restricted cash equivalents	12	10
Accounts receivable, less allowance for uncollectible accounts of $12 million and $11 million, respectively	215	192
Inventories	32	30
Prepayments of income taxes	17	27
Income taxes receivable	111	5
Assets and accrued interest related to uncertain tax positions	14	—
Prepaid expenses and other	28	11
Total Current Assets	435	281
INVESTMENTS AND OTHER ASSETS		
Regulatory assets	603	694
Prepaid pension expense	109	88
Income taxes receivable	27	133
Restricted cash equivalents	14	17
Assets and accrued interest related to uncertain tax positions	6	12
Derivative assets	4	8
Other	12	12
Total Investments and Other Assets	775	964
PROPERTY, PLANT AND EQUIPMENT		
Property, plant and equipment	2,861	2,771
Accumulated depreciation	(748)	(787)
Net Property, Plant and Equipment	2,113	1,984
TOTAL ASSETS	$ 3,323	$ 3,229

The accompanying Notes are an integral part of these Consolidated Financial Statements.

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2013	December 31, 2012
	(millions of dollars, except shares)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 117	$ 133
Current portion of long-term debt	48	108
Accounts payable and accrued liabilities	129	147
Accounts payable due to associated companies	12	14
Taxes accrued	11	10
Interest accrued	19	15
Customer deposits	25	25
Other	20	22
Total Current Liabilities	381	474
DEFERRED CREDITS		
Regulatory liabilities	82	102
Deferred income tax liabilities, net	815	766
Investment tax credits	6	6
Other postretirement benefit obligations	36	34
Derivative liabilities	14	11
Other	17	18
Total Deferred Credits	970	937
LONG-TERM LIABILITIES		
Long-term debt	853	760
Transition Bonds issued by ACE Funding	226	256
Total Long-Term Liabilities	1,079	1,016
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
EQUITY		
Common stock, $3.00 par value, 25,000,000 shares authorized, 8,546,017 shares outstanding	26	26
Premium on stock and other capital contributions	651	576
Retained earnings	216	200
Total Equity	893	802
TOTAL LIABILITIES AND EQUITY	$ 3,323	$ 3,229

The accompanying Notes are an integral part of these Consolidated Financial Statements.

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2013	2012
	(millions of dollars)	
OPERATING ACTIVITIES		
Net income	$ 41	$ 36
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation and amortization	101	92
Deferred income taxes	43	72
Changes in:		
Accounts receivable	(23)	(47)
Inventories	(2)	(5)
Prepaid expenses	(11)	(12)
Regulatory assets and liabilities, net	35	(20)
Accounts payable and accrued liabilities	2	26
Pension contributions	(30)	(30)
Income tax-related prepayments, receivables and payables	(1)	(51)
Other assets and liabilities	15	13
Net Cash From Operating Activities	170	74
INVESTING ACTIVITIES		
Investment in property, plant and equipment	(204)	(186)
Department of Energy capital reimbursement awards received	1	2
Net other investing activities	1	(3)
Net Cash Used By Investing Activities	(202)	(187)
FINANCING ACTIVITIES		
Dividends paid to Parent	(25)	(35)
Capital contribution from Parent	75	—
Issuances of long-term debt	100	—
Reacquisitions of long-term debt	(96)	(30)
(Repayments) issuances of short-term debt, net	(16)	93
Net other financing activities	(6)	1
Net Cash From Financing Activities	32	29
Net Decrease in Cash and Cash Equivalents	—	(84)
Cash and Cash Equivalents at Beginning of Period	6	91
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 6	$ 7
SUPPLEMENTAL CASH FLOW INFORMATION		
Cash (received) paid for income taxes (includes payments to PHI for federal income taxes)	$ (21)	$ 4

The accompanying Notes are an integral part of these Consolidated Financial Statements.

ATLANTIC CITY ELECTRIC COMPANY
CONSOLIDATED STATEMENT OF EQUITY
(Unaudited)

(millions of dollars, except shares)	Common Stock Shares	Common Stock Par Value	Premium on Stock	Retained Earnings	Total
BALANCE, DECEMBER 31, 2012	8,546,017	$ 26	$ 576	$ 200	$802
Net Income	—	—	—	9	9
BALANCE, MARCH 31, 2013	8,546,017	26	576	209	811
Net Income	—	—	—	7	7
Capital contribution from Parent	—	—	75	—	75
BALANCE, JUNE 30, 2013	8,546,017	26	651	216	893
Net Income	—	—	—	25	25
Dividends on common stock	—	—	—	(25)	(25)
BALANCE, SEPTEMBER 30, 2013	8,546,017	$ 26	$ 651	$ 216	$893

The accompanying Notes are an integral part of these Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

ATLANTIC CITY ELECTRIC COMPANY

(1) ORGANIZATION

Atlantic City Electric Company (ACE) is engaged in the transmission and distribution of electricity in southern New Jersey. ACE also provides Default Electricity Supply, which is the supply of electricity at regulated rates to retail customers in its service territory who do not elect to purchase electricity from a competitive energy supplier. Default Electricity Supply is known as Basic Generation Service in New Jersey. ACE is a wholly owned subsidiary of Conectiv, LLC, which is wholly owned by Pepco Holdings, Inc. (Pepco Holdings or PHI).

(2) SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation

ACE's unaudited consolidated financial statements are prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). Pursuant to the rules and regulations of the Securities and Exchange Commission, certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted. Therefore, these consolidated financial statements should be read along with the annual consolidated financial statements included in ACE's annual report on Form 10-K for the year ended December 31, 2012. In the opinion of ACE's management, the unaudited consolidated financial statements contain all adjustments (which all are of a normal recurring nature) necessary to state fairly ACE's financial condition as of September 30, 2013, in accordance with GAAP. The year-end December 31, 2012 consolidated balance sheet included herein was derived from audited consolidated financial statements, but does not include all disclosures required by GAAP. Interim results for the three and nine months ended September 30, 2013 may not be indicative of ACE's results that will be realized for the full year ending December 31, 2013.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities in the consolidated financial statements and accompanying notes. Although ACE believes that its estimates and assumptions are reasonable, they are based upon information available to management at the time the estimates are made. Actual results may differ significantly from these estimates.

Significant matters that involve the use of estimates include the assessment of contingencies, future cash flows and fair value amounts for use in asset impairment evaluations, fair value calculations for derivative instruments, pension and other postretirement benefits assumptions, the assessment of the probability of recovery of regulatory assets, accrual of storm restoration costs, accrual of unbilled revenue, recognition of changes in network service transmission rates for prior service year costs, accrual of self-insurance reserves for general and auto liability claims, and income tax provisions and reserves. Additionally, ACE is subject to legal, regulatory and other proceedings and claims that arise in the ordinary course of its business. ACE records an estimated liability for these proceedings and claims when it is probable that a loss has been incurred and the loss is reasonably estimable.

Consolidation of Variable Interest Entities

ACE assesses its contractual arrangements with variable interest entities to determine whether it is the primary beneficiary and thereby has to consolidate the entities in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 810. The guidance addresses conditions under which an entity should be consolidated based upon variable interests rather than voting interests.

ACE Power Purchase Agreements

ACE is a party to three power purchase agreements (PPAs) with unaffiliated, non-utility generators (NUGs) totaling 459 megawatts (MWs). One of the agreements ends in 2016 and the other two end in 2024. Since 2004, ACE has been unable to obtain sufficient information to determine whether these three entities were variable interest entities or if ACE was the primary beneficiary. As a result, ACE applied the scope exemption from the consolidation guidance for enterprises that have not been able to obtain such information.

Purchase activities with the NUGs, including excess power purchases not covered by the PPA, for the three months ended September 30, 2013 and 2012 were approximately $61 million and $56 million, respectively, of which approximately $54 million and $53 million, respectively, consisted of power purchases under the PPAs. Purchase activities with the NUGs for the nine months ended September 30, 2013 and 2012 were approximately $168 million and $156 million, respectively, of which approximately $157 million and $151 million, respectively, consisted of power purchases under the PPAs. The power purchase costs are recoverable from ACE's customers through regulated rates.

Atlantic City Electric Transition Funding LLC

Atlantic City Electric Transition Funding LLC (ACE Funding) was established in 2001 by ACE solely for the purpose of securitizing authorized portions of ACE's recoverable stranded costs through the issuance and sale of bonds (Transition Bonds). The proceeds of the sale of each series of Transition Bonds have been transferred to ACE in exchange for the transfer by ACE to ACE Funding of the right to collect non-bypassable transition bond charges (the Transition Bond Charges) from ACE customers pursuant to bondable stranded costs rate orders issued by the New Jersey Board of Public Utilities (NJBPU) in an amount sufficient to fund the principal and interest payments on the Transition Bonds and related taxes, expenses and fees (Bondable Transition Property). ACE collects the Transition Bond Charges from its customers on behalf of ACE Funding and the holders of the Transition Bonds. The assets of ACE Funding, including the Bondable Transition Property, and the Transition Bond Charges collected from ACE's customers, are not available to creditors of ACE. The holders of the Transition Bonds have recourse only to the assets of ACE Funding. ACE owns 100 percent of the equity of ACE Funding and consolidates ACE Funding in its consolidated financial statements as ACE is the primary beneficiary of ACE Funding under the variable interest entity consolidation guidance.

ACE Standard Offer Capacity Agreements

In April 2011, ACE entered into three Standard Offer Capacity Agreements (SOCAs) by order of the NJBPU, each with a different generation company. The SOCAs were established under a New Jersey law enacted to promote the construction of qualified electric generation facilities in New Jersey. The SOCAs are 15-year, financially settled transactions approved by the NJBPU that allow generation companies to receive payments from, or require them to make payments to, ACE based on the difference between the fixed price in the SOCAs and the price for capacity that clears PJM Interconnection, LLC (PJM). Each of the other electric distribution companies (EDCs) in New Jersey has entered into SOCAs having the same terms with the same generation companies. ACE's share of the payments received from or the payments made to the generation companies is currently estimated to be approximately 15 percent, based on its proportionate share of the total New Jersey electric load for all EDCs. The NJBPU has ordered that ACE is obligated to distribute to its distribution customers all payments it receives from the generation companies and may recover from its distribution customers all payments it makes to the generation companies.

In May 2013, all three generation companies under the SOCAs bid into the PJM 2016-2017 capacity auction. Two of the generators cleared the capacity auction, while the third did not. For each SOCA that clears the capacity auction, ACE records a derivative asset (liability) for the estimated fair value of that SOCA and records an offsetting regulatory liability (asset) as described in more detail in Note (10), "Derivative Instruments and Hedging Activities," and Note (11), "Fair Value Disclosures." Effective July 1, 2013, the SOCA with the third generation company was terminated as the generation company did not clear a PJM capacity auction by the commencement date required under the SOCA. ACE has concluded that consolidation of the generation companies is not required.

For additional discussion regarding litigation associated with the SOCAs, see Note (6), "Regulatory Matters."

Taxes Assessed by a Governmental Authority on Revenue-Producing Transactions

Taxes included in ACE's gross revenues were $3 million and $6 million for the three months ended September 30, 2013 and 2012, respectively, and $8 million and $13 million for the nine months ended September 30, 2013 and 2012, respectively.

(3) NEWLY ADOPTED ACCOUNTING STANDARDS

Balance Sheet (ASC 210)

In December 2011, the FASB issued new disclosure requirements for financial assets and financial liabilities, such as derivatives, that are subject to contractual netting arrangements. The new disclosure requirements include information about the gross exposure of the instruments and the net exposure of the instruments under contractual netting arrangements, how the exposures are presented in the financial statements, and the terms and conditions of the contractual netting arrangements. ACE adopted the new guidance during the first quarter of 2013 and concluded it did not have a material impact on its consolidated financial statements.

(4) RECENTLY ISSUED ACCOUNTING STANDARDS, NOT YET ADOPTED

Joint and Several Liability Arrangements (ASC 405)

In February 2013, the FASB issued new recognition and disclosure requirements for certain joint and several liability arrangements where the total amount of the obligation is fixed at the reporting date. For arrangements within the scope of this standard, ACE will be required to include in its liabilities the additional amounts it expects to pay on behalf of its co-obligors, if any. ACE will also be required to provide additional disclosures including the nature of the arrangements with its co-obligors, the total amounts outstanding under the arrangements between ACE and its co-obligors, the carrying value of the liability, and the nature and limitations of any recourse provisions that would enable recovery from other entities.

The new requirements would be effective retroactively beginning on January 1, 2014, with implementation required for prior periods if joint and several liability arrangement obligations exist as of January 1, 2014. ACE is evaluating the impact of this new guidance on its consolidated financial statements.

Income Taxes (ASC 740)

In July 2013, the FASB issued new guidance that will require the netting of certain unrecognized tax benefits against a deferred tax asset for a loss or other similar tax carryforward that would apply upon settlement of the uncertain tax position. The new requirements are effective prospectively beginning with ACE's March 31, 2014 consolidated financial statements for all unrecognized tax benefits existing at the adoption date. Retrospective implementation and early adoption of the guidance are permitted. ACE is evaluating the impact of this new guidance on its consolidated financial statements.

(5) SEGMENT INFORMATION

ACE operates its business as one regulated utility segment, which includes all of its services as described above.

(6) REGULATORY MATTERS

Rate Proceedings

Electric Distribution Base Rates

On December 11, 2012, ACE submitted an application with the NJBPU, updated on January 4, 2013, to increase its electric distribution base rates by approximately $70.4 million (excluding sales-and-use taxes), based on a requested return on equity (ROE) of 10.25%. This proposed net increase was comprised of (i) a proposed increase to ACE's distribution rates of approximately $72.1 million and (ii) a net decrease to ACE's Regulatory Asset Recovery Charge (a customer charge to recover deferred, NJBPU-approved expenses incurred as part of ACE's public service obligation) in the amount of approximately $1.7 million. The requested rate increase was primarily for the purposes of continuing to implement reliability-related investments and recovering system restoration costs associated with the derecho storm in June 2012 and Hurricane Sandy in October 2012. On June 21, 2013, the NJBPU approved a settlement of the parties (the NJ Rate Settlement) providing for an increase in ACE's distribution base rates in the amount of $25.5 million, based on an ROE of 9.75%. The base distribution revenue increase includes full recovery of the approximately $70.0 million in incremental storm restoration costs incurred as a result of recent major storm events, including the derecho storm and Hurricane Sandy, by including the related capital costs of approximately $44.2 million in rate base and amortizing the related deferred operation and maintenance expenses of approximately $25.8 million over a three-year period. Rates were effective on July 1, 2013.

In a March 20, 2013 order, the NJBPU established a generic proceeding to evaluate the prudence of major storm event restoration costs and expenses. Each New Jersey EDC was directed to file a separate proceeding for the evaluation of these costs. Those portions of ACE's 2012 electric base rate filing pertaining to the recovery of major storm event expenditures were to be evaluated in the context of the generic proceeding. On April 9, 2013, ACE filed a petition with the NJBPU to comply with the NJBPU's generic storm cost order. All other issues in ACE's base rate filing remained unchanged in the electric base rate proceeding discussed above. In its order approving the NJ Rate Settlement, the NJBPU found that (i) ACE's April 9, 2013 petition met all the requirements of the NJBPU's March 20, 2013 order, and (ii) the major storm event costs for the June 2012 derecho storm and Hurricane Sandy may be recovered in ACE's electric distribution base rate case, discussed above.

Update and Reconciliation of Certain Under-Recovered Balances

In February 2012, ACE submitted a petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE's long-term power purchase contracts with the NUGs, (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program for low income customers) and ACE's uncollected accounts and (iii) operating costs associated with ACE's residential appliance cycling program. The filing proposed to recover the projected deferred under-recovered balance related to the NUGs of $113.8 million as of May 31, 2012 through a four-year amortization schedule. In June 2012, the NJBPU approved a stipulation of settlement signed by the parties, which provided for provisional rates that went into effect on July 1, 2012. The net impact of adjusting the charges (consisting of both the annual impact of the proposed four-year amortization of the historical under-recovered NUG balances of $127.0 million as of June 30, 2012 and the going-forward cost recovery of all the other charges for the period July 1, 2012 through May 31, 2013, and including associated changes in sales-and-use taxes) is an overall annual rate increase of approximately $55.3 million. The rates were deemed "provisional" because ACE's filing had not been updated for actual revenues and expenses for May and June 2012 until the March 5, 2013 petition described below was filed. A review by the NJBPU of the final underlying costs for reasonableness and prudence will be completed. On June 11, 2013, this matter was transmitted to the New Jersey Office of Administrative Law (OAL) for hearing, which has been scheduled for December 2013.

On March 5, 2013, ACE submitted a new petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE's long-term power purchase contracts with the NUGs, (ii) costs related to surcharges for the New Jersey Societal Benefit Program and ACE's uncollected accounts and (iii) operating costs associated with ACE's residential appliance cycling program. The filing proposed to recover the forecasted above-market NUG costs of approximately $67.9 million for the period June 1, 2013 through May 31, 2014, the projected deferred under-recovered balance related to the NUGs of approximately $40.8 million as of May 31, 2013, and an additional approximately $32.9 million associated with the deferred under-recovered balance that is being amortized over a four-year amortization period. In May 2013, the NJBPU approved a stipulation of settlement signed by the parties, which provided for provisional rates that went into effect on June 1, 2013. The net impact of adjusting the charges updated for actual data through March 31, 2013 (consisting of both the second year impact of the stipulated four-year amortization of the historical under-recovered NUG balances and the going-forward cost recovery of all the other charges for the period June 1, 2013 through May 31, 2014, and including associated changes in sales-and-use taxes) is an overall annual rate increase of approximately $52.2 million (this rate increase is in addition to the approximately $55.3 million approved by the NJBPU in June 2012, as discussed in the above paragraph). The rates were deemed "provisional" because ACE's filing has not been updated for actual revenues and expenses for April and May 2013. A review by NJBPU of the final underlying costs for reasonableness and prudence will be completed. On June 11, 2013, this matter was transmitted to the OAL for hearing, which has been scheduled for December 2013.

Service Extension Contributions Refund Order

On July 19, 2013, in compliance with a 2012 Appellate Division of New Jersey court decision, the NJBPU released an order requiring utilities to issue refunds to persons or entities that paid non-refundable contributions for service extensions to certain areas described as "Areas Not Designated for Growth." The order is limited to eligible contributions paid between March 20, 2005 and December 20, 2009. ACE is processing the refund requests that meet the eligibility criteria established in the order as they are received. A stakeholder process has been initiated by the NJBPU to amend its rules regarding these types of service extensions (the Main Extension Rules) as a result of the Appellate Division's decision. The stakeholder process is expected to result in a final rulemaking that will amend the Main Extension Rules and address remaining issues related to the refund of these contributions, including deadlines for submission of refund requests. Although ACE believes it received approximately $11 million of contributions between March 20, 2005 and December 20, 2009, it is currently unable to reasonably estimate the amount that it may be required to refund using the eligibility criteria established by the order. At this time, ACE does not expect any such amount refunded will have a material effect on its consolidated financial condition, results of operations or cash flows, as any amounts that may be refunded will generally increase the value of ACE's property, plant and equipment and may ultimately be recovered through depreciation and cost of service.

Generic Consolidated Tax Adjustment Proceeding

In January 2013, the NJBPU initiated a generic proceeding to examine whether a consolidated tax adjustment (CTA) should continue to be used, and if so, how it should be calculated in determining a utility's cost of service. Under the current NJPBU policy related to the CTA, when a New Jersey utility is included in a consolidated group income tax return, an allocated amount of any reduction in the consolidated group's taxes as a result of losses by affiliates is used to reduce the utility's rate base, upon which the utility earns a return. Consequently, the NJBPU's current policy related to the CTA would substantially reduce ACE's rate base and ACE's position is that the CTA should be eliminated. A stakeholder process has been initiated by the NJBPU to aid in this examination. No formal schedule has been set for the remainder of the proceeding or for the issuance of a decision.

ACE Standard Offer Capacity Agreements

In April 2011, ACE entered into three SOCAs by order of the NJBPU, each with a different generation company, as more fully described in Note (2), "Significant Accounting Policies – Consolidation of Variable Interest Entities – ACE Standard Offer Capacity Agreements" and Note (10), "Derivative Instruments and Hedging Activities." ACE and the other New Jersey EDCs entered into the SOCAs under protest, arguing that the EDCs were denied due process and that the SOCAs violate certain of the requirements under the New Jersey law under which the SOCAs were established (the NJ SOCA Law). On October 22, 2013, in light of the decision of the U.S. District Court for the District of New Jersey described below, the Appellate Division dismissed the appeals filed by the EDCs and generators, without prejudice subject to the parties exercising their appellate rights in the Federal courts.

In February 2011, ACE joined other plaintiffs in an action filed in the U.S. District Court for the District of New Jersey challenging the NJ SOCA Law on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. On October 11, 2013, the Federal district court issued a ruling that the NJ SOCA Law is preempted by the Federal Power Act and violates the Supremacy Clause and is therefore null and void. On October 21, 2013, a joint motion to stay the Federal district court's decision pending appeal was filed by the NJBPU and one of the SOCA generation companies. In that motion, the NJBPU notified the Federal district court that it would take no action to force implementation of the SOCAs pending the appeal or such other action – such as FERC approval of the SOCAs – that would cure the constitutional issues to the Federal district court's satisfaction. On October 25, 2013, the Federal district court issued an order denying the joint motion to stay and ruling that the SOCAs are void, invalid and unenforceable. On October 31, 2013, one of the SOCA generation companies filed a notice of appeal of the October 25, 2013 Federal district court decision. PHI expects the October 11, 2013 and October 25, 2013 decisions to be appealed by the NJBPU and possibly by the other SOCA generation company. In light of the Federal district court order, ACE expects to derecognize in the fourth quarter of 2013 both the derivative asset (liability) for the estimated fair value for the SOCAs and the offsetting regulatory liability (asset).

One of the three SOCAs was terminated effective July 1, 2013 because of an event of default of the generation company that was a party to the SOCA.

Transmission ROE Challenge

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Electric Municipal Corporation, Inc., filed a joint complaint with FERC against ACE, Potomac Electric Power Company (Pepco), an affiliate of ACE, and Delmarva Power & Light Company (DPL), an affiliate of ACE, as well as Baltimore Gas and Electric Company. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that ACE provides. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for ACE is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. ACE believes the allegations in this complaint are without merit and is vigorously contesting it. On April 3, 2013, ACE filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable.

(7) PENSION AND OTHER POSTRETIREMENT BENEFITS

ACE accounts for its participation in its parent's single-employer plans, Pepco Holdings' non-contributory retirement plan (the PHI Retirement Plan) and the Pepco Holdings, Inc. Welfare Plan for Retirees, as participation in multiemployer plans. PHI's pension and other postretirement net periodic benefit cost for the three months ended September 30, 2013 and 2012, before intercompany allocations from the PHI Service Company, were $20 million and $28 million, respectively. ACE's allocated share was $4 million and $6 million for the three months ended September 30, 2013 and 2012, respectively. PHI's pension and other postretirement net periodic benefit cost for the nine months ended September 30, 2013 and 2012, before intercompany allocations from the PHI Service Company, were $74 million and $84 million, respectively. ACE's allocated share of the net periodic benefit cost was $14 million and $18 million for the nine months ended September 30, 2013 and 2012, respectively.

In the first quarter of 2013, ACE made a discretionary tax-deductible contribution to the PHI Retirement Plan of $30 million. In the first quarter of 2012, ACE made a discretionary tax-deductible contribution to the PHI Retirement Plan of $30 million.

Other Postretirement Benefit Plan Amendment

During 2013, PHI approved two amendments to its other postretirement benefits plan. These amendments impacted the retiree medical plan and the retiree life insurance benefits, and will be effective on January 1, 2014. As a result of the amendments, which were cumulatively significant, PHI remeasured its projected benefit obligation for other postretirement benefits as of July 1, 2013. The remeasurement is expected to result in a $2 million reduction in ACE's net periodic benefit cost for other postretirement benefits during 2013. Approximately 30% of net periodic other postretirement benefit costs are capitalized.

(8) DEBT

Credit Facility

PHI, Pepco, DPL and ACE maintain an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. On August 1, 2011, PHI, Pepco, DPL and ACE entered into an amended and restated credit agreement which, on August 2, 2012, was amended to extend the term of the credit facility to August 1, 2017 and to amend the pricing schedule to decrease certain fees and interest rates payable to the lenders under the facility. On June 6, 2013, as permitted under the existing terms of the credit agreement, PHI, Pepco, DPL and ACE provided to the agent and lenders under the credit agreement, a notice requesting a one-year extension of the credit facility termination date. The request was approved and the new termination date is August 1, 2018. All of the terms and conditions as well as pricing remain the same.

The aggregate borrowing limit under the amended and restated credit facility is $1.5 billion, all or any portion of which may be used to obtain loans and up to $500 million of which may be used to obtain letters of credit. The facility also includes a swingline loan sub-facility, pursuant to which each company may make same day borrowings in an aggregate amount not to exceed 10% of the total amount of the facility. Any swingline loan must be repaid by the borrower within fourteen days of receipt. The credit sublimit is $750 million for PHI and $250 million for each of Pepco, DPL and ACE. The sublimits may be increased or decreased by the individual borrower during the term of the facility, except that (i) the sum of all of the borrower sublimits following any such increase or decrease must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by (a) PHI may not exceed $1.25 billion, and (b) each of Pepco, DPL or ACE may not exceed the lesser of $500 million or the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the sublimit reallocations may not exceed eight per year during the term of the facility.

The interest rate payable by each company on utilized funds is, at the borrowing company's election, (i) the greater of the prevailing prime rate, the federal funds effective rate plus 0.5% and the one month London Interbank Offered Rate (LIBOR) plus 1.0%, or (ii) the prevailing Eurodollar rate, plus a margin that varies according to the credit rating of the borrower.

In order for a borrower to use the facility, certain representations and warranties must be true and correct, and the borrower must be in compliance with specified financial and other covenants, including (i) the requirement that each borrowing company maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the credit agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) with certain exceptions, a restriction on sales or other dispositions of assets, and (iii) a restriction on the incurrence of liens on the assets of a borrower or any of its significant subsidiaries other than permitted liens. The credit agreement contains certain covenants and other customary agreements and requirements that, if not complied with, could result in an event of default and the acceleration of repayment obligations of one or more of the borrowers thereunder. Each of the borrowers was in compliance with all covenants under this facility at September 30, 2013.

The absence of a material adverse change in PHI's business, property, results of operations or financial condition is not a condition to the availability of credit under the credit agreement. The credit agreement does not include any rating triggers.

As of September 30, 2013 and December 31, 2012, the amount of cash plus borrowing capacity under the credit facility available to meet the liquidity needs of PHI's utility subsidiaries in the aggregate was $471 million and $477 million, respectively. ACE's borrowing capacity under the credit facility at any given time depends on the amount of the subsidiary borrowing capacity being utilized by Pepco and DPL and the portion of the total capacity being used by PHI.

Commercial Paper

ACE maintains an on-going commercial paper program to address its short-term liquidity needs. As of September 30, 2013, the maximum capacity available under the program was $250 million, subject to available borrowing capacity under the credit facility.

ACE had $99 million of commercial paper outstanding at September 30, 2013. The weighted average interest rate for commercial paper issued by ACE during the nine months ended September 30, 2013 was 0.32% and the weighted average maturity of all commercial paper issued by ACE during the nine months ended September 30, 2013 was four days.

Financing Activities

Term Loan Agreement

On May 10, 2013, ACE entered into a $100 million term loan agreement, pursuant to which ACE has borrowed (and may not re-borrow) $100 million at a rate of interest equal to the prevailing Eurodollar rate, which is determined by reference to the LIBOR with respect to the relevant interest period, all as defined in the loan agreement, plus a margin of 0.75%. ACE's Eurodollar borrowings under the loan agreement may be converted into floating rate loans under certain circumstances, and, in that event, for so long as any loan remains a floating rate loan, interest would accrue on that loan at a rate per year equal to (i) the highest of (a) the prevailing prime rate, (b) the federal funds effective rate plus 0.5%, or (c) the one-month Eurodollar rate plus 1%, plus (ii) a margin of 0.75%. As of September 30, 2013, outstanding borrowings under the loan agreement bore interest at an annual rate of 0.94%, which is subject to adjustment from time to time. All borrowings under the loan agreement are unsecured, and the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement, must be repaid in full on or before November 10, 2014.

Under the terms of the term loan agreement, ACE must maintain compliance with specified covenants, including (i) the requirement that ACE maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the loan agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) a restriction on sales or other dispositions of assets, other than certain permitted sales and dispositions, and (iii) a restriction on the incurrence of liens (other than liens permitted by the loan agreement) on the assets of ACE. The loan agreement does not include any rating triggers. ACE was in compliance with all covenants under this loan agreement as of September 30, 2013.

Bond Payments

In July 2013, ACE Funding made principal payments of $7 million on its Series 2002-1 Bonds, Class A-3, and $2 million on its Series 2003-1 Bonds, Class A-2.

Bond Retirement

On August 1, 2013, ACE repaid at maturity $68.6 million of its 6.625% non-callable first mortgage bonds.

Financing Activities Subsequent to September 30, 2013

Bond Payments

In October 2013, ACE Funding made principal payments of $8 million on its Series 2002-1 Bonds, Class A-3, and $3 million on its Series 2003-1 Bonds, Class A-2.

(9) INCOME TAXES

A reconciliation of ACE's consolidated effective income tax rates is as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2013		2012		2013		2012	
	(millions of dollars)							
Income tax at Federal statutory rate	$ 13	35.0%	$ 11	35.0%	$ 19	35.0%	$ 20	35.0%
Increases (decreases) resulting from:								
State income taxes, net of Federal effect	2	5.3%	2	6.1%	4	7.3%	3	5.3%
Change in estimates and interest related to uncertain and effectively settled tax positions	—	—	—	—	(9)	(16.4)%	—	—
Other, net	(2)	(6.1)%	—	(1.7)%	—	(0.4)%	(2)	(3.5)%
Consolidated income tax expense	$ 13	34.2%	$ 13	39.4%	$ 14	25.5%	$ 21	36.8%

Three Months Ended September 30, 2013 and 2012

ACE's consolidated effective tax rates for the three months ended September 30, 2013 and 2012 were 34.2% and 39.4%, respectively. The decrease in the effective tax rate primarily resulted from reductions in property-related temporary differences that are flowed through to income tax expense as part of the regulatory process.

Nine Months Ended September 30, 2013 and 2012

ACE's consolidated effective tax rates for the nine months ended September 30, 2013 and 2012 were 25.5% and 36.8%, respectively. The change in the effective tax rate primarily resulted from changes in estimates and interest related to uncertain and effectively settled tax positions. In the first quarter of 2013, ACE recorded an interest benefit of $6 million as discussed further below. In the first quarter of 2012, ACE recorded an interest benefit as a result of the effective settlement with the Internal Revenue Service with respect to the methodology used historically to calculate deductible mixed service costs.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which ACE is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. As a result of the court's ruling in this case, PHI determined in the first quarter of 2013 that it could no longer support its current assessment with respect to the likely outcome of tax positions associated with its cross-border energy lease investments held by its wholly-owned subsidiary Potomac Capital Investment Corporation, and PHI recorded a charge of $377 million (after-tax) in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $54 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in ACE recording a $6 million interest benefit in the first quarter of 2013.

Final IRS Regulations on Repair of Tangible Property

In September 2013, the IRS issued final regulations on expense versus capitalization of repairs with respect to tangible personal property. The regulations are effective for tax years beginning on or after January 1, 2014, and provide an option to early adopt the final regulations for tax years beginning on or after January 1, 2012. It is expected that the IRS will issue revenue procedures that will describe how taxpayers may implement the final regulations. The final repair regulations retain the operative rule that the Unit of Property for network assets is determined by the taxpayer's particular facts and circumstances except as provided in published guidance. In 2012, with the filing of its 2011 tax return, PHI filed a request for an automatic change in accounting method related to repairs of its network assets in accordance with IRS Revenue Procedure 2011-43. ACE does not expect the effects of the final regulations to be significant and will continue to evaluate the impact of the new guidance on its consolidated financial statements.

(10) DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

ACE was ordered to enter into the SOCAs by the NJBPU, and under the SOCAs, ACE would receive payments from or make payments to electric generation facilities based on (i) the difference between the fixed price in the SOCAs and the price for capacity that clears PJM and (ii) ACE's annual proportion of the total New Jersey load relative to the other EDCs in New Jersey, which is currently estimated to be 15 percent. ACE began applying derivative accounting to two of its SOCAs as of June 30, 2012 because the generators cleared the 2015-2016 PJM capacity auction in May 2012. In May 2013, all three generation companies under the SOCAs bid into the PJM 2016-2017 capacity auction. Two of the generators cleared the capacity auction, while the third did not. On July 1, 2013, the SOCA with the third generation company was terminated as the generation company did not clear a PJM capacity auction by the commencement date required under the SOCA. The fair value of the derivatives embedded in the SOCAs are deferred as Regulatory Assets or Regulatory Liabilities because the NJBPU has allowed full recovery from ACE's distribution customers for all payments made by ACE, and ACE's distribution customers would be entitled to all payments received by ACE.

As of September 30, 2013 and December 31, 2012, ACE had non-current Derivative Assets of $4 million and $8 million, respectively, and non-current Derivative Liabilities of $14 million and $11 million, respectively, associated with the two SOCAs and an offsetting Regulatory Liability and Regulatory Asset, respectively, of the same amounts. As of September 30, 2013 and December 31, 2012, ACE had 180 MWs of capacity in a long position, with no collateral or netting applicable to the capacity. Unrealized gains and losses associated with these capacity derivatives, which netted to unrealized losses of zero and $1 million for the three months ended September 30, 2013 and 2012, respectively, and unrealized losses of $7 million and $1 million for the nine months ended September 30, 2013 and 2012, respectively, have been deferred as regulatory liabilities and regulatory assets.

As further discussed in Note (7), "Regulatory Matters," in light of a Federal district court order issued on October 25, 2013, ACE expects to derecognize in the fourth quarter of 2013, the derivative asset of $4 million and the derivative liability of $14 million as of September 30, 2013 related to the SOCAs, as well as the offsetting regulatory liability (asset).

(11) FAIR VALUE DISCLOSURES

Financial Instruments Measured at Fair Value on a Recurring Basis

ACE applies FASB guidance on fair value measurement and disclosures (ASC 820) that established a framework for measuring fair value and expanded disclosures about fair value measurements. As defined in the guidance, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). ACE utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. Accordingly, ACE utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1) and the lowest priority to unobservable inputs (level 3).

The following tables set forth, by level within the fair value hierarchy, ACE's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2013 and December 31, 2012. As required by the guidance, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. ACE's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair Value Measurements at September 30, 2013			
Description	**Total**	**Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)**	**Significant Other Observable Inputs (Level 2) (a)**	**Significant Unobservable Inputs (Level 3)**
		(millions of dollars)		
ASSETS				
Derivative instruments (b)				
Capacity (c)	$ 4	$ —	$ —	$ 4
Cash equivalents				
Treasury fund	27	27	—	—
	$ 31	$ 27	$ —	$ 4
LIABILITIES				
Derivative instruments (b)				
Capacity (c)	$ 14	$ —	$ —	$ 14
	$ 14	$ —	$ —	$ 14

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the nine months ended September 30, 2013.
(b) The fair values of derivative assets and liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents derivatives associated with the ACE SOCAs.

Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1) (a)	Significant Other Observable Inputs (Level 2) (a)	Significant Unobservable Inputs (Level 3)
	Fair Value Measurements at December 31, 2012			
		(millions of dollars)		
ASSETS				
Derivative instruments (b)				
Capacity (c)	$ 8	$ —	$ —	$ 8
Cash equivalents				
Treasury fund	27	27	—	—
	$ 35	$ 27	$ —	$ 8
LIABILITIES				
Derivative instruments (b)				
Capacity (c)	$ 11	$ —	$ —	$ 11
Executive deferred compensation plan liabilities				
Life insurance contracts	1	—	1	—
	$ 12	$ —	$ 1	$ 11

(a) There were no transfers of instruments between level 1 and level 2 valuation categories during the year ended December 31, 2012.
(b) The fair values of derivative assets and liabilities reflect netting by counterparty before the impact of collateral.
(c) Represents derivatives associated with the ACE SOCAs.

ACE classifies its fair value balances in the fair value hierarchy based on the observability of the inputs used in the fair value calculation as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using broker quotes in liquid markets and other observable data. Level 2 also includes those financial instruments that are valued using methodologies that have been corroborated by observable market data through correlation or by other means. Significant assumptions are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

The level 2 liability associated with the life insurance policies represents a deferred compensation obligation, the value of which is tracked via underlying insurance sub-accounts. The sub-accounts are designed to mirror existing mutual funds and money market funds that are observable and actively traded.

Level 3 – Pricing inputs that are significant and generally less observable than those from objective sources. Level 3 includes those financial instruments that are valued using models or other valuation methodologies.

Derivative instruments categorized as level 3 represent capacity under the SOCAs entered into by ACE.

ACE used a discounted cash flow methodology to estimate the fair value of the capacity derivatives embedded in the SOCAs. ACE utilized an external valuation specialist to estimate annual zonal PJM capacity prices through the 2030-2031 auction. The capacity price forecast was based on various assumptions that impact the cost of constructing new generation facilities, including zonal load forecasts, zonal fuel and energy prices, generation capacity and transmission planning, and environmental legislation and regulation. ACE reviewed the assumptions and resulting capacity price forecast for reasonableness. ACE used the capacity price forecast to estimate future cash flows. A significant change in the forecasted prices would have a significant impact on the estimated fair value of the SOCAs. ACE employed a discount rate reflective of the estimated weighted average cost of capital for merchant generation companies since payments under the SOCAs are contingent on providing generation capacity.

The tables below summarize the primary unobservable inputs used to determine the fair value of ACE's level 3 instruments and the range of values that could be used for those inputs as of September 30, 2013 and December 31, 2012:

Type of Instrument	Fair Value at September 30, 2013 (millions of dollars)	Valuation Technique	Unobservable Input	Range
Capacity contracts, net	$ (10)	Discounted cash flow	Discount rate	5% - 9%

Type of Instrument	Fair Value at December 31, 2012 (millions of dollars)	Valuation Technique	Unobservable Input	Range
Capacity contracts, net	$ (3)	Discounted cash flow	Discount rate	5% - 9%

ACE used values within these ranges as part of its fair value estimates. A significant change in any of the unobservable inputs within these ranges would have an insignificant impact on the reported fair value as of September 30, 2013 and December 31, 2012.

A reconciliation of the beginning and ending balances of ACE's fair value measurements using significant unobservable inputs (level 3) for the nine months ended September 30, 2013 and 2012 is shown below:

	Capacity Nine Months Ended September 30, 2013	2012
	(millions of dollars)	
Beginning balance as of January 1	$ (3)	$ —
Total gains (losses) (realized and unrealized):		
Included in income	—	—
Included in accumulated other comprehensive loss	—	—
Included in regulatory liabilities and regulatory assets	(7)	(1)
Purchases	—	—
Issuances	—	—
Settlements	—	—
Transfers in (out) of level 3	—	—
Ending balance as of September 30	$ (10)	$ (1)

Other Financial Instruments

The estimated fair values of ACE's debt instruments that are measured at amortized cost in ACE's consolidated financial statements and the associated levels of the estimates within the fair value hierarchy as of September 30, 2013 and December 31, 2012 are shown in the tables below. As required by the fair value measurement guidance, debt instruments are classified in their entirety within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. ACE's assessment of the significance of a particular input to the fair value measurement requires the exercise of judgment, which may affect the valuation of fair value debt instruments and their placement within the fair value hierarchy levels.

The fair value of Long-term debt and Transition Bonds issued by ACE Funding categorized as level 2 is based on a blend of quoted prices for the debt and quoted prices for similar debt on the measurement date. The blend places more weight on current pricing information when determining the final fair value measurement. The fair value information is provided by brokers and ACE reviews the methodologies and results.

The fair value of Long-term debt categorized as level 3 is based on a discounted cash flow methodology using observable inputs, such as the U.S. Treasury yield, and unobservable inputs, such as credit spreads, because quoted prices for the debt or similar debt in active markets were insufficient.

	Fair Value Measurements at September 30, 2013			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(millions of dollars)			
LIABILITIES				
Debt instruments				
Long-term debt (a)	$ 978	$ —	$ 760	$ 218
Transition Bonds issued by ACE Funding (b)	299	—	299	—
	$1,277	$ —	$ 1,059	$ 218

(a) The carrying amount for Long-term debt is $860 million as of September 30, 2013.
(b) The carrying amount for Transition Bonds issued by ACE Funding, including amounts due within one year, is $267 million as of September 30, 2013.

	Fair Value Measurements at December 31, 2012			
Description	Total	Quoted Prices in Active Markets for Identical Instruments (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(millions of dollars)			
LIABILITIES				
Debt instruments				
Long-term debt (a)	$1,016	$ —	$ 884	$ 132
Transition Bonds issued by ACE Funding (b)	341	—	341	—
	$1,357	$ —	$ 1,225	$ 132

(a) The carrying amount for Long-term debt is $829 million as of December 31, 2012.
(b) The carrying amount for Transition Bonds issued by ACE Funding, including amounts due within one year, is $295 million as of December 31, 2012.

The carrying amounts of all other financial instruments in the accompanying consolidated financial statements approximate fair value.

(12) COMMITMENTS AND CONTINGENCIES

General Litigation

In September 2011, an asbestos complaint was filed in the New Jersey Superior Court, Law Division, against ACE (among other defendants) asserting claims under New Jersey's Wrongful Death and Survival statutes. The complaint, filed by the estate of a decedent who was the wife of a former employee of ACE, alleges that the decedent's mesothelioma was caused by exposure to asbestos brought home by her husband on his work clothes. New Jersey courts have recognized a cause of action against a premise owner in a so-called "take home" case if it can be shown that the harm was foreseeable. In this case, the complaint seeks recovery of an unspecified amount of damages for, among other things, the decedent's past medical expenses, loss of earnings, and pain and suffering between the time of injury and death, and asserts a punitive damage claim. At this time, ACE has concluded that a loss is reasonably possible with respect to this matter, but ACE was unable to estimate an amount or range of reasonably possible loss because the damages sought are indeterminate and the matter involves facts that ACE believes are distinguishable from the facts of the "take-home" cause of action recognized by the New Jersey courts. This case remains pending.

In October 2010, a farm combine came into and remained in contact with a primary electric line in ACE's service territory in New Jersey. As a result, two individuals operating the combine received fatal electrical contact injuries. While attempting to rescue those two individuals, another individual sustained third-degree burns to his torso and upper extremities. In September 2012, the individual who received third-degree burns filed suit in New Jersey Superior Court, Salem County. In October 2012, an additional suit was filed in the same court by the estate of one of the deceased individuals. Plaintiffs in both cases allege that ACE was negligent in the design, construction, erection, operation and maintenance of its poles, power lines, and equipment, and that ACE failed to warn and protect the public from the foreseeable dangers of farm equipment contacting electric lines. ACE is investigating the incident involved and discovery is ongoing. At this time, ACE has concluded that a loss is reasonably possible with respect to these claims, but ACE is unable to estimate an amount or range of reasonably possible loss because the damages sought are indeterminate and the matter remains under investigation.

Environmental Matters

ACE is subject to regulation by various federal, regional, state and local authorities with respect to the environmental effects of its operations, including air and water quality control, solid and hazardous waste disposal and limitations on land use. Although penalties assessed for violations of environmental laws and regulations are not recoverable from customers of ACE, environmental clean-up costs incurred by ACE generally are included in its cost of service for ratemaking purposes. The total accrued liabilities for the environmental contingencies of ACE described below at September 30, 2013 are summarized as follows:

	Legacy Generation - Regulated
	(millions of dollars)
Beginning balance as of January 1	$ 1
Accruals	—
Payments	—
Ending balance as of September 30	1
Less amounts in Other Current Liabilities	—
Amounts in Other Deferred Credits	$ 1

Franklin Slag Pile Site

In November 2008, ACE received a general notice letter from the U.S. Environmental Protection Agency (EPA) concerning the Franklin Slag Pile site in Philadelphia, Pennsylvania, asserting that ACE is a potentially responsible party (PRP) that may have liability for clean-up costs with respect to the site and for the costs of implementing an EPA-mandated remedy. EPA's claims are based on ACE's sale of boiler slag from the B.L. England generating facility, then owned by ACE, to MDC Industries, Inc. (MDC) during the period June 1978 to May 1983. EPA claims that the boiler slag ACE sold to MDC contained copper and lead, which are hazardous substances under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA), and that the sales transactions may have constituted an arrangement for the disposal or treatment of hazardous substances at the site, which could be a basis for liability under CERCLA. The EPA letter also states that, as of the date of the letter, EPA's expenditures for response measures at the site have exceeded $6 million. EPA's feasibility study for this site conducted in 2007 identified a range of alternatives for permanent remedial measures with varying cost estimates, and the estimated cost of EPA's preferred alternative is approximately $6 million.

ACE believes that the B.L. England boiler slag sold to MDC was a valuable material with various industrial applications and, therefore, the sale was not an arrangement for the disposal or treatment of any hazardous substances as would be necessary to constitute a basis for liability under CERCLA. ACE intends to contest any claims to the contrary made by EPA. In a May 2009 decision arising under CERCLA, which did not involve ACE, the U.S. Supreme Court rejected an EPA argument that the sale of a useful product constituted an arrangement for disposal or treatment of hazardous substances. While this decision supports ACE's position, at this time ACE cannot predict how EPA will proceed with respect to the Franklin Slag Pile site, or what portion, if any, of the Franklin Slag Pile site response costs EPA would seek to recover from ACE. Costs to resolve this matter are not expected to be material and are expensed as incurred.

Ward Transformer Site

In April 2009, a group of PRPs with respect to the Ward Transformer site in Raleigh, North Carolina, filed a complaint in the U.S. District Court for the Eastern District of North Carolina, alleging cost recovery and/or contribution claims against a number of entities, including ACE, based on its alleged sale of transformers to Ward Transformer, with respect to past and future response costs incurred by the PRP group in performing a removal action at the site. In a March 2010 order, the court denied the defendants' motion to dismiss. The litigation is moving forward with certain "test case" defendants (not including ACE) filing summary judgment motions regarding liability. The case has been stayed as to the remaining defendants pending rulings upon the test cases. In a January 31, 2013 order, the district court granted summary judgment for the test case defendant whom plaintiffs alleged was liable based on its sale of transformers to Ward Transformer. The district court's order, which plaintiffs have appealed to the U.S. Court of Appeals for the Fourth Circuit, addresses only the liability of the test case defendant. ACE has concluded that a loss is reasonably possible with respect to this matter, but was unable to estimate an amount or range of reasonably possible losses to which it may be exposed. ACE does not believe that it had extensive business transactions, if any, with the Ward Transformer site.

(13) RELATED PARTY TRANSACTIONS

PHI Service Company provides various administrative and professional services to PHI and its regulated and unregulated subsidiaries, including ACE. The cost of these services is allocated in accordance with cost allocation methodologies set forth in the service agreement using a variety of factors, including the subsidiaries' share of employees, operating expenses, assets and other cost methods. These intercompany transactions are eliminated by PHI in consolidation and no profit results from these transactions at PHI. PHI Service Company costs directly charged or allocated to ACE for the three months ended September 30, 2013 and 2012 were approximately $28 million and $31 million, respectively. PHI Service Company costs directly charged or allocated to ACE for the nine months ended September 30, 2013 and 2012 were approximately $87 million and $86 million, respectively.

In addition to the PHI Service Company charges described above, ACE's consolidated financial statements include the following related party transactions in the consolidated statements of income:

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
	(millions of dollars)			
Meter reading services provided by Millennium Account Services LLC (an ACE affiliate) (a)	$ (1)	$ (1)	$ (3)	$ (3)
Intercompany lease transactions (a)	—	—	(1)	(1)
Intercompany use revenue (b)	1	—	2	1

(a) Included in Other Operation and Maintenance expense.
(b) Included in Operating Revenue

As of September 30, 2013 and December 31, 2012, ACE had the following balances on its consolidated balance sheets due to related parties:

	September 30, 2013	December 31, 2012
	(millions of dollars)	
Payable to Related Party (current) (a)		
PHI Service Company	$ (12)	$ (13)
Other	—	(1)
Total	$ (12)	$ (14)

(a) Included in Accounts Payable Due to Associated Companies.

Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The information required by this item is contained herein, as follows:

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Pepco Holdings, Inc.

General Overview

PHI, a Delaware corporation incorporated in 2001, is a holding company that, through its regulated public utility subsidiaries, is engaged primarily in the transmission, distribution and default supply of electricity and the distribution and supply of natural gas (Power Delivery). Through Pepco Energy Services, Inc. and its subsidiaries (collectively, Pepco Energy Services), PHI provides energy savings performance contracting services, high voltage underground transmission cabling, and low voltage electric construction and maintenance services, and designs, constructs and operates combined heat and power and central energy plants. For additional discussion, see "Pepco Energy Services" below.

Each of Power Delivery and Pepco Energy Services constitutes a separate segment for financial reporting purposes. Through its subsidiary Potomac Capital Investment Corporation (PCI), PHI maintained a portfolio of cross-border energy lease investments. During the third quarter of 2013, PHI completed the termination of its interests in its cross-border energy lease investments. As a result, beginning with PHI's consolidated financial statements for the three and nine months ended September 30, 2013, the cross-border energy lease investments, which comprised substantially all of the operations of the Other Non-Regulated segment, are being accounted for as discontinued operations. The remaining operations of the Other Non-Regulated segment, which no longer meet the definition of a separate segment for financial reporting purposes, are being included in Corporate and Other.

The following table sets forth the percentage contributions to consolidated operating revenue and consolidated operating income (loss) from continuing operations attributable to PHI segments:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Percentage of Consolidated Operating Revenue				
Power Delivery	97%	96%	96%	95%
Pepco Energy Services	4%	4%	4%	5%
Corporate and Other	(1)%	—	—	—
Percentage of Consolidated Operating Income (Loss)				
Power Delivery	98%	99%	96%	97%
Pepco Energy Services	(1)%	(3)%	1%	(1)%
Corporate and Other	3%	4%	3%	4%
Percentage of Power Delivery Operating Revenue				
Power Delivery Electric	98%	98%	96%	96%
Power Delivery Gas	2%	2%	4%	4%

Power Delivery

Power Delivery Electric consists primarily of the transmission, distribution and default supply of electricity, and Power Delivery Gas consists of the distribution and supply of natural gas.

Each utility comprising Power Delivery is a regulated public utility in the jurisdictions that comprise its service territory. Each utility is responsible for the distribution of electricity and, in the case of DPL, natural gas, in its service territory, for which it is paid tariff rates established by the applicable local public service commission in each jurisdiction. Each utility also supplies electricity at regulated rates to retail customers in its service territory who do not elect to purchase electricity from a competitive energy supplier. The regulatory term for this supply service is Standard Offer Service (SOS) in Delaware, the District of Columbia and Maryland, and Basic Generation Service (BGS) in New Jersey. In this report, these supply service obligations are referred to generally as Default Electricity Supply.

Each of Pepco, DPL and ACE is responsible for the transmission of wholesale electricity into and across its service territory. The rates each utility is permitted to charge for the wholesale transmission of electricity are regulated by the Federal Energy Regulatory Commission (FERC). Transmission rates are updated annually based on a FERC-approved formula methodology.

The profitability of Power Delivery depends on its ability to recover costs and earn a reasonable return on its capital investments through the rates it is permitted to charge. Operating results also can be affected by economic conditions, energy prices, the impact of energy efficiency measures on customer usage of electricity and weather.

Power Delivery's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of Pepco and DPL in Maryland and of Pepco in the District of Columbia, revenue is not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) was implemented that provides for a fixed distribution charge per customer rather than a charge based upon energy usage. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from retail customers in Maryland and the District of Columbia to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. A comparable revenue decoupling mechanism for DPL electricity and natural gas customers in Delaware is under consideration by the Delaware Public Service Commission (DPSC).

In accounting for the BSA in Maryland and the District of Columbia, a Revenue Decoupling Adjustment is recorded representing either (i) a positive adjustment equal to the amount by which revenue from retail distribution sales falls short of the revenue that Pepco and DPL are entitled to earn based on the approved distribution charge per customer or (ii) a negative adjustment equal to the amount by which revenue from such distribution sales exceeds the revenue that Pepco and DPL are entitled to earn based on the approved distribution charge per customer.

Since 2010, PHI has implemented comprehensive reliability enhancement plans which include various initiatives to improve electrical system reliability, including:

- the identification and upgrading of under-performing feeder lines;
- the addition of new facilities to support load;
- the installation of distribution automation systems on both the overhead and underground network systems;
- the rejuvenation and replacement of underground residential cables;
- selective undergrounding of portions of existing above-ground primary feeder lines, where appropriate to improve reliability;
- improvements to substation supply lines; and
- enhanced vegetation management.

Power Delivery Initiatives and Activities

Smart Grid

PHI is building a smart grid which is designed to meet the challenges of rising energy costs, respond to concerns about the environment, improve reliability, provide timely and accurate customer information and address government energy reduction goals. A central component of the smart grid is advanced metering infrastructure (AMI), which is a system that collects, measures and analyzes energy usage data from advanced digital electric and gas meters known as smart meters. The installation of smart meters is subject to the approval of applicable state regulators. The District of Columbia Public Service Commission (DCPSC), the Maryland Public Service Commission (MPSC) and the DPSC have approved the creation of regulatory assets to defer AMI costs between rate cases and to accrue returns on the deferred costs. Thus, these costs will be recovered in the future through base rates; however, for AMI costs incurred by Pepco in Maryland with respect to test years after 2011, pursuant to an MPSC order, the recovery of such costs will be allowed when Pepco demonstrates that the AMI system is cost effective. The MPSC's July 2013 order in Pepco's November 2012 electric distribution base rate application excluded the cost of AMI meters from Pepco's rate base until such time as Pepco demonstrates the cost effectiveness of the AMI system. As a result, costs for AMI meters incurred with respect to the 2012 test year and beyond will be treated as other incremental AMI costs incurred in conjunction with the deployment of the AMI system that are deferred and on which a return is earned, but only until such cost effectiveness has been demonstrated and such costs are included in rates. Approval of AMI has been deferred by the New Jersey Board of Public Utilities (NJBPU) for ACE in New Jersey.

Meter installation and activation are substantially complete for Pepco customers in the District of Columbia and are expected to be completed in the fourth quarter of 2013 for Pepco customers in Maryland. In 2012, the MPSC approved the deployment of AMI for electric customers in DPL's Maryland service territory, and installation began in the second quarter of 2013. Electric meter installation and activation are complete for DPL electric customers in Delaware; installation of smart meters for natural gas delivery customers in Delaware is expected to be completed in the fourth quarter of 2013.

In April 2010, PHI signed agreements to formalize $168 million in awards from the U.S. Department of Energy to support the rollout of smart grid initiatives. In the Pepco service area, $149 million was awarded for AMI, direct load control, distribution automation and communications infrastructure, while in the ACE service area, $19 million was awarded for direct load control, distribution automation and communications infrastructure. The grants effectively reduce the project costs of these initiatives. The cumulative award payments received by Pepco and ACE as of September 30, 2013 were $139 million and $16 million, respectively.

Mitigation of Regulatory Lag

An important factor in the ability of each of Pepco, DPL and ACE to earn its authorized rate of return is the willingness of applicable public service commissions to adequately recognize forward-looking costs in the utility's rate structure in order to address the shortfall in revenues due to the delay in time or "lag" between when costs are incurred and when they are reflected in rates. This delay is commonly known as "regulatory lag." Each of Pepco, DPL and ACE is currently experiencing significant regulatory lag because its investment in the rate base and its operating expenses are outpacing revenue growth.

In an effort to minimize the effects of regulatory lag, Pepco's and DPL's District of Columbia, Delaware and Maryland base rate case filings in 2011 each included a request for approval from the applicable state regulatory commissions of (i) a reliability investment recovery mechanism (RIM) to recover reliability-related capital expenditures incurred between base rate cases and (ii) the use by the applicable utility of fully forecasted test years in future base rate cases. In June 2012, the MPSC rejected Pepco's and DPL's requests to implement the RIM and did not endorse the use by Pepco and DPL of fully forecasted test years in future rate cases. However, the MPSC did permit an adjustment to the rate base of Pepco and DPL to reflect the actual cost of reliability plant additions outside the test year. In the District of Columbia, the DCPSC denied Pepco's request for approval of a RIM in 2012, and reserved final judgment on the appropriateness of the use by Pepco of a fully forecasted test year in future rate cases. In Delaware, a settlement agreement approved by the DPSC in DPL's 2011 electric distribution base rate case did not include approval of a RIM or the use of fully forecasted test years in future DPL rate cases, but it did provide that the parties will meet and discuss alternate regulatory methodologies for the mitigation of regulatory lag.

Each of PHI's utility subsidiaries will continue to seek cost recovery from applicable public service commissions to reduce the effects of regulatory lag. There can be no assurance that any attempts by PHI's utility subsidiaries to mitigate regulatory lag will be approved, or that even if approved, the cost recovery mechanisms will fully mitigate the effects of regulatory lag. Until such time as any cost recovery mechanisms are approved, PHI's utility subsidiaries plan to file rate cases at least annually in an effort to align more closely the revenue and cash flow levels of PHI's utility subsidiaries with other operation and maintenance spending and capital investments. Pepco filed its electric distribution base rate case in March 2013 in the District of Columbia, and expects to file its next electric distribution base rate case in Maryland by the end of 2013. DPL filed electric distribution base rate cases in both Delaware and Maryland in March 2013, and filed a natural gas distribution case in December 2012. ACE filed an electric distribution base rate case in December 2012. In their respective electric distribution base rate cases filed in Maryland, each of Pepco and DPL included a proposed three-year Grid Resiliency Charge rider intended to reduce regulatory lag. In July and August 2013, the MPSC issued orders in the Pepco and DPL Maryland base rate cases, respectively, that only partially approved the proposed Grid Resiliency Charge. See Note (7), "Regulatory Matters – Rate Proceedings – Maryland," to the consolidated financial statements of PHI for more information about these base rate cases. On July 26, 2013, Pepco filed a notice of appeal of this MPSC order. Furthermore, Pepco is continuing to review the impact of this order and consider other actions to more closely align its spending in Maryland to the revenue received while maintaining compliance with the MPSC's established standards applicable to Pepco.

In Delaware, DPL filed a multi-year rate plan on October 2, 2013, referred to as the Forward Looking Rate Plan (FLRP). As proposed, the FLRP would establish electric distribution base rates for a period of four years into the future. See Note (7), "Regulatory Matters – Rate Proceedings – Delaware – Forward Looking Rate Plan," to the consolidated financial statements of PHI for more information about this filing.

MAPP Project

On August 24, 2012, the board of PJM terminated the MAPP project and removed it from PJM's regional transmission expansion plan. PHI had been directed to construct the MAPP project, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region's transmission system. In December 2012, PHI submitted a filing to FERC seeking recovery of $88 million of abandoned MAPP costs over a five-year period. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

In February 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of Pepco and DPL, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs. FERC reduced the ROE applicable to the abandoned costs from the previously approved 12.8% incentive ROE to 10.8% by disallowing 200 basis points of ROE adders. FERC also denied recovery of 50% (calculated by PHI to be $2 million) of the prudently incurred abandoned costs prior to November 1, 2008, the date of FERC's MAPP incentive order. PHI believes that the February 2013 FERC order is not consistent with prior precedent and is vigorously pursuing its rights to recover all prudently incurred abandoned costs associated with the MAPP project, as well as the full ROE previously approved by FERC. In April 2013, PHI filed a rehearing request of the February 2013 FERC order challenging the reduction of the ROE applicable to the abandoned costs, as well as the denial of 50% of the costs incurred prior to November 1, 2008. On that same date, a group of public advocates from Maryland, Delaware, New Jersey, Virginia, West Virginia and Pennsylvania also filed a rehearing request challenging the 10.8% ROE authorized in FERC's order, arguing that PHI is not entitled to any rate of return on the abandoned costs and that FERC improperly failed to set the ROE for hearing. PHI is currently engaged in settlement negotiations in this matter; however, PHI cannot predict when a final FERC decision in this proceeding will be issued.

As of September 30, 2013, PHI had a regulatory asset related to the MAPP abandoned costs of approximately $71 million, representing the original filing amount of approximately $88 million of abandoned costs referred to above less: (i) approximately $2 million of disallowed costs written off in 2013; (ii) $5 million of materials transferred to inventories for use on other projects; and (iii) $10 million of amortization expense recorded in 2013. The regulatory asset balance includes the costs of land, land rights, engineering and design, environmental services, and project management and administration. PHI intends to reduce further the amount of the regulatory asset by any amounts recovered from the sale or alternative use of the land.

Transmission ROE Challenge

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Electric Municipal Corporation, Inc., filed a joint complaint with FERC against Pepco, DPL and ACE, as well as Baltimore Gas and Electric Company (BGE). The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that PHI's utilities provide. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for PHI's utilities is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. PHI, Pepco, DPL and ACE believe the allegations in this complaint are without merit and are vigorously contesting it. On April 3, 2013, Pepco, DPL and ACE filed their answer to this complaint, requesting that FERC dismiss the complaint against them on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable.

Pepco Energy Services

Since 2010, Pepco Energy Services has been focused on growing its energy savings performance contracting services business in the federal, state and local government markets. Activity in the state and local government markets, which are Pepco Energy Services' largest markets, slowed significantly in 2012, due to, among other factors, lower energy prices that have lessened the economic benefits of energy savings projects and the reluctance of state and local governments to incur new debt associated with these projects. As a result of the slowdown, Pepco Energy Services believes that new business in these markets will remain challenged for the foreseeable future. Consequently, Pepco Energy Services reduced resources and personnel in 2012, has limited geographic expansion in the energy savings services business and has refocused its existing resources on developing business in the federal government market and continuing to pursue combined heat and power projects.

Other

Between 1990 and 1999, PCI, through various subsidiaries, entered into certain transactions involving investments in aircraft and aircraft equipment, railcars and other assets. In connection with these transactions, PCI recorded deferred tax assets in prior years of $101 million in the aggregate. Following events that took place during the first quarter of 2013, which included (i) court decisions in favor of the IRS with respect to both Consolidated Edison's cross-border lease transaction and another taxpayer's structured transactions, (ii) the change in PHI's tax position with respect to the tax benefits associated with its cross-border energy leases, and (iii) PHI's decision in March 2013 to begin to pursue the early termination of its remaining cross-border energy lease investments (which represented a substantial portion of the remaining assets within PCI) without the intent to reinvest these proceeds in income-producing assets, management evaluated the likelihood that PCI will be able to realize the $101 million of deferred tax assets in the future. Based on this evaluation, PCI established valuation allowances against these deferred tax assets totaling $101 million in the first quarter of 2013. This charge is included in Corporate and Other in Note (5), "Segment Information," in the notes to the consolidated financial statements.

<u>*Discontinued Operations*</u>

Cross-Border Energy Lease Investments

Through its subsidiary PCI, PHI held a portfolio of cross-border energy lease investments. During July 2013, PHI completed the termination of its interest in its cross-border energy lease investments. With the completion of the early termination of the cross-border energy leases, the cross-border energy lease investment activity is being accounted for as a discontinued operation.

As discussed in Note (14), "Commitments and Contingencies – PHI's Cross-Border Energy Lease Investments," PHI is involved in ongoing litigation with the IRS concerning certain benefits associated with previously held investments in cross-border energy leases. On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which PHI is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. As a result of the court's ruling in this case, PHI determined in the first quarter of 2013 that its tax position with respect to the benefits associated with its cross-border energy leases no longer met the more-likely-than-not standard of recognition for accounting purposes, and PCI recorded non-cash charges of $323 million (after-tax) in the first quarter of 2013 and $6 million (after-tax) in the second quarter of 2013, consisting of the following components:

- A non-cash pre-tax charge of $373 million ($313 million after-tax) to reduce the carrying value of these cross-border energy lease investments under Financial Accounting Standards Board (FASB) guidance on leases (Accounting Standards Codification (ASC 840)). This pre-tax charge was originally recorded in the consolidated statement of income as a reduction in operating revenue and is now reflected in income (loss) from discontinued operations, net of income taxes.
- A non-cash charge of $16 million after-tax to reflect the anticipated additional net interest expense under FASB guidance for income taxes (ASC 740), related to estimated federal and state income tax obligations for the period over which the tax benefits may be disallowed. This after-tax charge was originally recorded in the consolidated statement of income as an increase in income tax expense and is now reflected in income (loss) from discontinued operations, net of income taxes. The after-tax interest charge for PHI on a consolidated basis was $70 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in the recognition of a $12 million interest benefit for the Power Delivery segment and interest expense of $16 million for PCI and $66 million for Corporate and Other, respectively.

Retail Electric and Natural Gas Supply Businesses of Pepco Energy Services

In December 2009, PHI announced the wind-down of the retail energy supply component of the Pepco Energy Services business which is comprised of the retail electric and natural gas supply businesses. Pepco Energy Services implemented the wind-down by not entering into any new retail electric or natural gas supply contracts while continuing to perform under its existing retail electric and natural gas supply contracts through their respective expiration dates. On March 21, 2013, Pepco Energy Services entered into an agreement whereby a third party assumed all the rights and obligations of the remaining retail natural gas supply customer contracts, and the associated supply obligations, inventory and derivative contracts. The transaction was completed on April 1, 2013. In addition, Pepco Energy Services completed the wind-down of its retail electric supply business in the second quarter of 2013 by terminating its remaining customer supply and wholesale purchase obligations beyond June 30, 2013.

The operations of Pepco Energy Services' retail electric and natural gas supply businesses are being accounted for as a discontinued operation and are no longer a part of the Pepco Energy Services segment for financial reporting purposes.

Earnings Overview

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012

Net income (loss) for the three months ended September 30, 2013 and 2012, by operating segment, is set forth in the table below (in millions of dollars):

	2013	2012	Change
Power Delivery	$114	$ 92	$ 22
Pepco Energy Services	(1)	(3)	2
Corporate and Other	(3)	(2)	(1)
Net Income from Continuing Operations	110	87	23
Discontinued Operations	8	25	(17)
Total PHI Net Income	$118	$112	$ 6

Net income from continuing operations for the three months ended September 30, 2013 was $110 million, or $0.44 per share, compared to net income from continuing operations of $87 million, or $0.38 per share, for the three months ended September 30, 2012.

Net income from discontinued operations for the three months ended September 30, 2013 was $8 million, or $0.04 per share, compared to $25 million, or $0.11 per share, for the three months ended September 30, 2012.

Discussion of Operating Segment Net Income Variances:

Power Delivery's $22 million increase in earnings was primarily due to the following:

- An increase of $26 million from electric distribution base rate increases (Pepco in the District of Columbia and Maryland, DPL in Maryland and Delaware, and ACE in New Jersey).
- An increase of $8 million due to lower operation and maintenance expense, primarily associated with higher storm restoration and system maintenance in 2012, partially offset by recovery in 2012 of 2011 storm restoration costs and regulatory expenses.
- An increase of $3 million due to a favorable tax provision true-up related to the difference between the 2012 federal tax provision and the amount included on the tax return as filed.
- An increase of $2 million due to higher transmission revenue attributable to higher rates related to increases in transmission plant investment.
- A decrease of $5 million due to higher depreciation and amortization expense associated primarily with regulatory assets and increases in plant investment, partially offset by lower depreciation rates.
- A decrease of $5 million due to lower sales from milder summer weather.
- A decrease of $3 million due to lower non-weather related average customer usage in New Jersey and Delaware.
- A decrease of $2 million associated with Default Electricity Supply margins for DPL Delaware, primarily due to favorable adjustments in 2012 related to allowed returns on net uncollectible expense and regulatory taxes.

Pepco Energy Services' $2 million decrease in net loss was primarily due to the following:

- An increase of $2 million primarily due to a favorable adjustment to power plant asset retirement obligations, and higher margins at its combined heat and power operations in Atlantic City.
- An increase of $1 million due to asset impairment charges in 2012 that did not reoccur in 2013.

Discussion of Discontinued Operations Variance:

Net income from discontinued operations for the three months ended September 30, 2013, decreased by $17 million as a result of the following:

- An after-tax gain of $9 million recorded in 2012 related to the early termination of certain cross-border energy leases ($39 million pre-tax), partially offset by an after-tax gain of $7 million recorded in 2013, associated with the completion of the early termination of the remaining cross-border energy lease investments ($11 million pre-tax).
- A decrease of $10 million as a result of holding fewer cross-border energy leases in 2013.
- Lower sales volume in 2013 at Pepco Energy Services due to the wind-down of the retail electric and natural gas supply businesses.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

Net income (loss) for the nine months ended September 30, 2013 and 2012, by operating segment, is set forth in the table below (in millions of dollars):

	2013	2012	Change
Power Delivery	$ 228	$193	$ 35
Pepco Energy Services	3	(2)	5
Corporate and Other	(179)	(7)	(172)
Net Income from Continuing Operations	52	184	(132)
Discontinued Operations	(322)	58	(380)
Total PHI Net (Loss) Income	$(270)	$242	$ (512)

Net income from continuing operations for the nine months ended September 30, 2013 was $52 million, or $0.21 per share, compared to net income from continuing operations of $184 million, or $0.80 per share, for the nine months ended September 30, 2012.

Net income from continuing operations for the nine months ended September 30, 2013 included the charges set forth below in Corporate and Other, which are presented, where applicable, net of related federal and state income taxes and are in millions of dollars:

Charge to establish valuation allowances related to certain PCI deferred tax assets	$101
Charge to reflect the anticipated additional interest expense on estimated federal and state income tax obligations allocated to Corporate and Other (as if it were a separate taxpayer) resulting from the change in assessment of the tax benefits associated with the cross-border energy lease investments ($102 million pre-tax)	$ 66

Excluding the items listed above, for the nine months ended September 30, 2013, net income from continuing operations would have been $219 million, or $0.90 per share. PHI discloses net income from continuing operations and related per share data excluding these items because management believes that these items are not representative of PHI's ongoing business operations. Management uses this information, and believes that such information is useful to investors, in evaluating PHI's period-over-period performance. The inclusion of this disclosure is intended to complement, and should not be considered as an alternative to, PHI's reported net income from continuing operations and related per share data in accordance with GAAP.

Net loss from discontinued operations for the nine months ended September 30, 2013 was $322 million, or $1.31 per share, compared to net income of $58 million, or $0.26 per share, for the nine months ended September 30, 2012.

Discussion of Operating Segment Net Income Variances:

Power Delivery's $35 million increase in earnings was primarily due to the following:

- An increase of $52 million from electric distribution base rate increases (Pepco in the District of Columbia and Maryland, DPL in Maryland and Delaware, and ACE in New Jersey).
- An increase of $5 million due to lower operation and maintenance expense, primarily associated with higher storm restoration and system maintenance in 2012, partially offset by recovery in 2012 of 2011 storm restoration costs and regulatory expenses.
- An increase of $3 million primarily due to higher sales from colder winter weather, partially offset by lower sales from milder summer weather.
- A decrease of $6 million due to higher interest expense resulting from an increase in outstanding debt.
- A decrease of $6 million associated with Default Electricity Supply margins for DPL Delaware, primarily due to favorable adjustments in 2012 related to allowed returns on net uncollectible expense and regulatory taxes.
- A decrease of $6 million due to higher depreciation and amortization expense associated primarily with regulatory assets and increases in plant investment, partially offset by lower depreciation rates.
- A decrease of $2 million due to lower non-weather related average customer usage in New Jersey and Delaware.

Pepco Energy Services' $5 million increase in earnings was primarily due to the following:

- An increase of $3 million due to asset impairment charges in 2012 that did not reoccur in 2013.
- An increase of $2 million primarily due to lower compensation expenses.

Corporate and Other's $172 million increase in net loss was primarily due to the following:

- An after-tax charge of $101 million to establish valuation allowances against certain PCI deferred tax assets.
- An after-tax charge of $66 million to reflect the anticipated additional interest expense allocated to Corporate and Other related to changes in PHI's consolidated estimated federal and state income tax obligations resulting from the change in assessment regarding the tax benefits related to the cross-border energy lease investments.

Discussion of Discontinued Operations Variance:

Net earnings from discontinued operations for the nine months ended September 30, 2013, decreased by $380 million to a net loss of $322 million as a result of the following:

- An aggregate after-tax charge of $313 million recorded in 2013 to reduce the carrying value of PCI's cross-border energy lease investments ($373 million pre-tax).
- An after-tax charge of $16 million recorded in the first quarter of 2013 to reflect the anticipated additional interest expense on estimated federal and state income tax obligations allocated to PCI (as if it were a separate taxpayer) resulting from the change in assessment of the tax benefits associated with the cross-border energy lease investments ($25 million pre-tax).
- An after-tax gain of $9 million recorded in the third quarter of 2012 related to the early termination of certain cross-border energy leases ($39 million pre-tax), partially offset by an after-tax loss of $2 million recorded in 2013, associated with the completion of the early termination of the remaining cross-border energy lease investments ($3 million pre-tax).
- A decrease of $24 million as a result of holding fewer cross-border energy leases in 2013.
- Lower sales volume in 2013 at Pepco Energy Services due to the wind-down of the retail electric and natural gas supply businesses.

Consolidated Results of Operations

The following results of operations discussion compares the three months ended September 30, 2013 to the three months ended September 30, 2012. All amounts in the tables (except sales and customers) are in millions of dollars.

Continuing Operations

Operating Revenue

A detail of the components of PHI's consolidated operating revenue is as follows:

	2013	2012	Change
Power Delivery	$1,298	$1,335	$ (37)
Pepco Energy Services	48	57	(9)
Corporate and Other	(2)	(3)	1
Total Operating Revenue	$1,344	$1,389	$ (45)

Power Delivery

The following table categorizes Power Delivery's operating revenue by type of revenue.

	2013	2012	Change
Regulated T&D Electric Revenue	$ 626	$ 599	$ 27
Default Electricity Supply Revenue	636	695	(59)
Other Electric Revenue	13	15	(2)
Total Electric Operating Revenue	1,275	1,309	(34)
Regulated Gas Revenue	17	18	(1)
Other Gas Revenue	6	8	(2)
Total Gas Operating Revenue	23	26	(3)
Total Power Delivery Operating Revenue	$1,298	$1,335	$ (37)

Regulated Transmission and Distribution (T&D) Electric Revenue includes revenue from the distribution of electricity, including the distribution of Default Electricity Supply, by PHI's utility subsidiaries to customers within their service territories at regulated rates. Regulated T&D Electric Revenue also includes transmission service revenue that PHI's utility subsidiaries receive as transmission owners from PJM at rates regulated by FERC. Transmission rates are updated annually based on FERC-approved formula methodology.

Default Electricity Supply Revenue is the revenue received from the supply of electricity by PHI's utility subsidiaries at regulated rates to retail customers who do not elect to purchase electricity from a competitive energy supplier. The costs related to Default Electricity Supply are included in Fuel and Purchased Energy. Default Electricity Supply Revenue also includes revenue from non-bypassable transition bond charges (Transition Bond Charges) that ACE receives, and pays to Atlantic City Electric Transition Funding LLC (ACE Funding), to fund the principal and interest payments on Transition Bonds issued by ACE Funding (Transition Bonds), and revenue in the form of transmission enhancement credits that PHI utility subsidiaries receive as transmission owners from PJM for approved regional transmission expansion plan costs.

Other Electric Revenue includes work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services include mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Regulated Gas Revenue includes the revenue DPL receives from on-system natural gas delivered sales and the transportation of natural gas for customers within its service territory at regulated rates.

Other Gas Revenue consists of DPL's off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers. Off-system sales are made possible when low demand for natural gas by regulated customers creates excess pipeline capacity.

Regulated T&D Electric

	2013	2012	Change
Regulated T&D Electric Revenue			
Residential	$ 247	$ 239	$ 8
Commercial and industrial	276	268	8
Transmission and other	103	92	11
Total Regulated T&D Electric Revenue	$ 626	$ 599	$ 27

	2013	2012	Change
Regulated T&D Electric Sales (Gigawatt hours (GWh))			
Residential	5,060	5,708	(648)
Commercial and industrial	8,214	8,605	(391)
Transmission and other	61	58	3
Total Regulated T&D Electric Sales	13,335	14,371	(1,036)

	2013	2012	Change
Regulated T&D Electric Customers (in thousands)			
Residential	1,643	1,639	4
Commercial and industrial	199	198	1
Transmission and other	2	2	—
Total Regulated T&D Electric Customers	1,844	1,839	5

The Pepco, DPL and ACE service territories are located within a corridor extending from the District of Columbia to southern New Jersey. These service territories are economically diverse and include key industries that contribute to the regional economic base:

- Commercial activities in the region include banking and other professional services, government, insurance, real estate, shopping malls, casinos, stand alone construction and tourism.
- Industrial activities in the region include chemical, glass, pharmaceutical, steel manufacturing, food processing and oil refining.

Regulated T&D Electric Revenue increased by $27 million primarily due to:

- An increase of $42 million due to distribution rate increases (Pepco in the District of Columbia effective October 2012, and in Maryland effective July 2012 and July 2013; DPL in Maryland effective July 2012 and September 2013, and Delaware effective July 2012; ACE effective November 2012).
- An increase of $5 million in transmission revenue rates effective June 1, 2013 related to increases in transmission plant investment and operating expenses.
- An increase of $4 million in transmission revenue related to the recovery of MAPP abandoned costs, as approved by FERC (which is offset in Depreciation and Amortization).

The aggregate amount of these increases was partially offset by:

- A decrease of $10 million due to lower non-weather related average customer usage in DPL and ACE.
- A decrease of $9 million due to lower sales primarily as a result of milder weather during the 2013 summer months, as compared to 2012.
- A decrease of $4 million primarily due to a Renewable Portfolio Surcharge rate decrease in Delaware effective May 2013 (which is substantially offset by corresponding decreases in Fuel and Purchased Energy and Depreciation and Amortization).
- A decrease of $1 million in distribution revenue due to lower pass-through revenue (which is substantially offset by a corresponding decrease in Other Taxes) primarily the result of a decrease in sales that resulted in a decrease in Montgomery County, Maryland utility taxes that are collected by Pepco on behalf of the jurisdiction.

Default Electricity Supply

	2013	2012	Change
Default Electricity Supply Revenue			
Residential	$426	$499	$ (73)
Commercial and industrial	165	160	5
Other	45	36	9
Total Default Electricity Supply Revenue	$636	$695	$ (59)

Other Default Electricity Supply Revenue consists primarily of (i) revenue from the resale by ACE in the PJM regional transmission organization (PJM RTO) market of energy and capacity purchased under contracts with unaffiliated non-utility generators (NUGs) and (ii) revenue from transmission enhancement credits.

	2013	2012	Change
Default Electricity Supply Sales (GWh)			
Residential	4,031	4,696	(665)
Commercial and industrial	1,430	1,547	(117)
Other	11	12	(1)
Total Default Electricity Supply Sales	5,472	6,255	(783)

	2013	2012	Change
Default Electricity Supply Customers (in thousands)			
Residential	1,339	1,382	(43)
Commercial and industrial	125	130	(5)
Other	—	—	—
Total Default Electricity Supply Customers	1,464	1,512	(48)

Default Electricity Supply Revenue decreased by $59 million primarily due to:

- A decrease of $41 million due to lower sales primarily as a result of milder weather during the 2013 summer months, as compared to 2012.
- A net decrease of $25 million due to lower non-weather related average customer usage in DPL and ACE, partially offset by higher Pepco customer usage.
- A decrease of $17 million due to lower sales, primarily as a result of customer migration to competitive suppliers.

The aggregate amount of these decreases was partially offset by:

- A net increase of $14 million as a result of higher Pepco and ACE Default Electricity Supply rates, partially offset by lower DPL rates.
- An increase of $11 million in wholesale energy and capacity resale revenues primarily due to higher market prices for the resale of electricity and capacity purchased from NUGs.

Regulated Gas

	2013	2012	Change
Regulated Gas Revenue			
Residential	$ 9	$ 10	$ (1)
Commercial and industrial	6	6	—
Transportation and other	2	2	—
Total Regulated Gas Revenue	$ 17	$ 18	$ (1)

	2013	2012	Change
Regulated Gas Sales (million cubic feet)			
Residential	406	410	(4)
Commercial and industrial	563	389	174
Transportation and other	1,255	1,290	(35)
Total Regulated Gas Sales	2,224	2,089	135

	2013	2012	Change
Regulated Gas Customers (in thousands)			
Residential	116	115	1
Commercial and industrial	9	9	—
Transportation and other	—	—	—
Total Regulated Gas Customers	125	124	1

DPL's natural gas service territory is located in New Castle County, Delaware. Several key industries contribute to the economic base as well as to growth, as follows:

- Commercial activities in the region include banking and other professional services, government, insurance, real estate, shopping malls and stand alone construction.
- Industrial activities in the region include chemical and pharmaceutical.

Regulated Gas Revenue decreased by $1 million primarily due to a Gas Cost Rate (GCR) decrease effective November 2012.

Other Gas

Other Gas Revenue decreased by $2 million primarily due to lower volumes for off-system sales to electric generators and gas marketers.

Pepco Energy Services

Pepco Energy Services' operating revenue decreased by $9 million primarily due to:

- A decrease of $5 million due to a reduction in streetlight construction service and underground transmission construction activities.
- A decrease of $3 million due to decreased energy services construction activities.

Operating Expenses

Fuel and Purchased Energy and Other Services Cost of Sales

A detail of PHI's consolidated Fuel and Purchased Energy and Other Services Cost of Sales is as follows:

	2013	2012	Change
Power Delivery	$578	$646	$ (68)
Pepco Energy Services	38	44	(6)
Corporate and Other	—	(4)	4
Total	$616	$686	$ (70)

Power Delivery

Power Delivery's Fuel and Purchased Energy consists of the cost of electricity and natural gas purchased by its utility subsidiaries to fulfill their respective Default Electricity Supply and Regulated Gas obligations and, as such, is recoverable from customers in accordance with the terms of public service commission orders. It also includes the cost of natural gas purchased for off-system sales. Fuel and Purchased Energy expense decreased by $68 million primarily due to:

- A decrease of $32 million due to lower electricity sales primarily as a result of milder weather during the 2013 summer months, as compared to 2012.

- A decrease of $31 million primarily due to customer migration to competitive suppliers.
- A decrease of $20 million in deferred electricity expense primarily due to higher DPL Default Electricity Supply rates and lower DPL Default Electricity Supply revenue rates, which resulted in a lower rate of recovery of Default Electricity Supply costs.
- A decrease of $3 million in the cost of gas purchases for off-system sales as a result of lower average gas prices and lower volume purchased.

The aggregate amount of these decreases was partially offset by a net increase of $20 million due to higher average electricity costs under Pepco and DPL Default Electricity Supply contracts, partially offset by lower ACE costs.

Pepco Energy Services

Pepco Energy Services' Fuel and Purchased Energy and Other Services Cost of Sales decreased by $6 million primarily due to:

- A decrease of $5 million due to a reduction in streetlight construction service and underground transmission construction activities.
- An increase of $2 million primarily due to expenses associated with an energy services operations and maintenance contract.

Other Operation and Maintenance

A detail of PHI's Other Operation and Maintenance expense is as follows:

	2013	2012	Change
Power Delivery	$213	$228	$ (15)
Pepco Energy Services	11	16	(5)
Corporate and Other	(16)	(16)	—
Total	$208	$228	$ (20)

Power Delivery

Other Operation and Maintenance expense for Power Delivery decreased by $15 million primarily due to:

- A decrease of $10 million in other storm restoration costs.
- A decrease of $4 million in employee-related costs, primarily benefit expenses.
- A decrease of $3 million associated with lower maintenance costs.
- A decrease of $3 million in customer service costs.

The aggregate amount of these decreases was partially offset by:

- An increase of $4 million due to 2012 total incremental storm restoration costs for major storm events as described in the following table:

	2013	2012	Change
Regulatory asset established for future recovery of January 2011 winter storm costs	$ —	$ (9)	$ 9
Costs associated with derecho storm (June 2012)	—	38	(38)
Regulatory assets established for future recovery of derecho storm costs	—	(33)	33
Total incremental major storm restoration costs	$ —	$ (4)	$ 4

  - In January 2011, Pepco incurred incremental storm restoration costs of $10 million associated with a severe winter storm, all of which were expensed in 2011. In July 2012, the MPSC issued an order allowing for the deferral and recovery of $9 million of such costs over a five-year period.
  - In the third quarter of 2012, Pepco, DPL and ACE incurred incremental storm restoration costs of $38 million associated with the June 2012 derecho which resulted in widespread damage to the electric distribution system in each of their service territories. PHI's utility subsidiaries deferred $33 million of these costs as regulatory assets to reflect the probable recovery of these storm restoration costs in Maryland and New Jersey. The MPSC approved the recovery of these costs in Maryland for both Pepco and DPL in its July and August 2013 rate orders, respectively, over a five-year period. ACE's stipulation of settlement approved by NJBPU in June 2013 provides for recovery of these costs in New Jersey over a three-year period. The remaining costs of $5 million relate to repair work completed in Delaware and the District of Columbia, which costs are not currently deferrable in those jurisdictions.

- An increase of $3 million resulting from 2012 deferred cost adjustments associated with DPL Default Electricity Supply. The deferred cost adjustments were primarily due to the under-recognition of allowed returns on net uncollectible expense and regulatory taxes in 2012.

Pepco Energy Services

Other Operation and Maintenance expense for Pepco Energy Services decreased by $5 million primarily due to:

- A decrease of $3 million in personnel costs in its energy savings services business primarily due to a reduction in the number of employees in the second half of 2012.
- A decrease of $1 million in operating, repairs and maintenance expenses at its combined heat and power operations in Atlantic City and its generating facilities.
- A decrease of $1 million associated with an accrual for an energy savings guarantee shortfall in 2012.

Depreciation and Amortization

Depreciation and Amortization expense increased by $2 million to $124 million in 2013 from $122 million in 2012 primarily due to:

- An increase of $4 million in amortization of MAPP abandoned costs (which is offset in T&D Electric Revenue).
- An increase of $4 million in amortization of regulatory assets primarily related to recoverable major storm costs and rate case costs.

The aggregate amount of these increases was partially offset by:

- A decrease of $4 million in the Delaware Renewable Energy Portfolio Standards deferral (which is substantially offset by a corresponding decrease in Regulated T&D Electric Revenue).
- A decrease of $2 million related to a favorable power plant asset retirement obligation adjustment in Pepco Energy Services.

Other Taxes

Other Taxes decreased by $2 million to $119 million in 2013 from $121 million in 2012. The decrease was primarily due to lower sales that resulted in a decrease in utility taxes that are collected and passed through by Power Delivery (substantially offset by a corresponding decrease in Regulated T&D Electric Revenue).

Deferred Electric Service Costs

Deferred Electric Service Costs, which relate only to ACE, represent (i) the over or under recovery of electricity costs incurred by ACE to fulfill its Default Electricity Supply obligation and (ii) the over or under recovery of New Jersey Societal Benefit Program (a public interest program for low income customers) costs incurred by ACE. The cost of electricity purchased is reported under Fuel and Purchased Energy and the corresponding revenue is reported under Default Electricity Supply Revenue. The cost of New Jersey Societal Benefit Programs is reported under Other Operation and Maintenance and the corresponding revenue is reported under Regulated T&D Electric Revenue.

Deferred Electric Service Costs increased by $13 million to an expense of $42 million in 2013 as compared to an expense of $29 million in 2012 primarily due to an increase in deferred electricity expense as a result of higher Default Electricity Supply and New Jersey Societal Benefit Programs revenue rates and lower electricity supply costs.

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $3 million to a net expense of $60 million in 2013 from a net expense of $57 million in 2012. The increase reflects a $2 million increase in interest expense primarily associated with higher long-term debt and $1 million associated with lower income related to the allowance for funds used during construction (AFUDC) that is applied to capital projects.

Income Tax Expense

PHI's income tax expense increased by $8 million to $65 million in 2013 from $57 million in 2012. PHI's consolidated effective tax rates for the three months ended September 30, 2013 and 2012 were 37.1% and 39.6%, respectively. The decrease in the effective tax rate primarily resulted from an increase in asset removal costs.

Discontinued Operations

PHI's income from discontinued operations, net of income taxes, is comprised of the following:

	2013	2012	Change
Cross-border energy lease investments	$ 7	$17	$ (10)
Pepco Energy Services' retail electric and natural gas supply businesses	1	8	(7)
Income from discontinued operations, net of income taxes	$ 8	$25	$ (17)

For the three months ended September 30, 2013 and 2012, income from discontinued operations, net of income taxes, was $8 million and $25 million, respectively. The decrease of $17 million was comprised of a decrease of $10 million related to PHI's cross-border lease investments and a decrease of $7 million related to the retail electric and natural gas businesses at Pepco Energy Services.

The decrease in income from discontinued operations, net of income taxes, for PHI's cross-border energy lease investments was primarily due to lower cross-border energy lease investment earnings as a result of holding fewer cross-border lease investments in 2013 and gains recorded on the early termination of certain leases within the cross-border energy lease portfolio in the third quarter of 2012, partially offset by the gain recorded on the early termination of the final lease investment during the third quarter of 2013.

The decrease in income from discontinued operations, net of income taxes, at Pepco Energy Services was due to a reduction in sales volume associated with the wind-down of the retail electric and natural gas supply businesses and a reduction in mark-to-market gains.

The following results of operations discussion compares the nine months ended September 30, 2013 to the nine months ended September 30, 2012. All amounts in the tables (except sales and customers) are in millions of dollars.

Continuing Operations

Operating Revenue

A detail of the components of PHI's consolidated operating revenue is as follows:

	2013	2012	Change
Power Delivery	$3,428	$3,374	$ 54
Pepco Energy Services	154	205	(51)
Corporate and Other	(7)	(10)	3
Total Operating Revenue	$3,575	$3,569	$ 6

Power Delivery

The following table categorizes Power Delivery's operating revenue by type of revenue.

	2013	2012	Change
Regulated T&D Electric Revenue	$1,625	$1,523	$ 102
Default Electricity Supply Revenue	1,620	1,681	(61)
Other Electric Revenue	46	46	—
Total Electric Operating Revenue	3,291	3,250	41
Regulated Gas Revenue	114	102	12
Other Gas Revenue	23	22	1
Total Gas Operating Revenue	137	124	13
Total Power Delivery Operating Revenue	$3,428	$3,374	$ 54

Regulated Transmission and Distribution (T&D) Electric Revenue includes revenue from the distribution of electricity, including the distribution of Default Electricity Supply, by PHI's utility subsidiaries to customers within their service territories at regulated rates. Regulated T&D Electric Revenue also includes transmission service revenue that PHI's utility subsidiaries receive as transmission owners from PJM at rates regulated by FERC. Transmission rates are updated annually based on FERC-approved formula methodology.

Default Electricity Supply Revenue is the revenue received from the supply of electricity by PHI's utility subsidiaries at regulated rates to retail customers who do not elect to purchase electricity from a competitive energy supplier. The costs related to Default Electricity Supply are included in Fuel and Purchased Energy. Default Electricity Supply Revenue also includes revenue from Transition Bond Charges that ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds, and revenue in the form of transmission enhancement credits that PHI utility subsidiaries receive as transmission owners from PJM for approved regional transmission expansion plan costs.

Other Electric Revenue includes work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services include mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Regulated Gas Revenue includes the revenue DPL receives from on-system natural gas delivered sales and the transportation of natural gas for customers within its service territory at regulated rates.

Other Gas Revenue consists of DPL's off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers. Off-system sales are made possible when low demand for natural gas by regulated customers creates excess pipeline capacity.

Regulated T&D Electric

	2013	2012	Change
Regulated T&D Electric Revenue			
Residential	$ 601	$ 555	$ 46
Commercial and industrial	733	699	34
Transmission and other	291	269	22
Total Regulated T&D Electric Revenue	$ 1,625	$ 1,523	$ 102

	2013	2012	Change
Regulated T&D Electric Sales (GWh)			
Residential	13,342	13,474	(132)
Commercial and industrial	22,887	23,493	(606)
Transmission and other	183	183	—
Total Regulated T&D Electric Sales	36,412	37,150	(738)

	2013	2012	Change
Regulated T&D Electric Customers (in thousands)			
Residential	1,643	1,639	4
Commercial and industrial	199	198	1
Transmission and other	2	2	—
Total Regulated T&D Electric Customers	1,844	1,839	5

Regulated T&D Electric Revenue increased by $102 million primarily due to:

- An increase of $86 million due to distribution rate increases (Pepco in the District of Columbia effective October 2012, and in Maryland effective July 2012 and July 2013; DPL in Maryland effective July 2012 and September 2013, and in Delaware effective July 2012; ACE effective November 2012).
- An increase of $11 million in transmission revenue rates effective June 1, 2012 and June 1, 2013 related to increases in transmission plant investment and operating expenses.

- An increase of $10 million in transmission revenue related to the recovery of MAPP abandoned costs, as approved by FERC (which is offset in Depreciation and Amortization).
- An increase of $7 million primarily due to a Renewable Portfolio Surcharge in Delaware effective June 2012 (which is substantially offset by a corresponding increase in Fuel and Purchased Energy and Depreciation and Amortization).
- An increase of $6 million primarily due to a rate increase in the New Jersey Societal Benefit Charge (related to the New Jersey Societal Benefit Program) effective July 2012 (which is offset in Deferred Electric Service Costs).
- An increase of $6 million in transmission revenue related to the resale by DPL of renewable energy in Delaware (which is substantially offset by a corresponding increase in Purchased Energy and Depreciation and Amortization).
- An increase of $4 million in transmission revenue primarily attributable to higher capacity revenue as a result of expanding Maryland demand-side management programs (which is substantially offset in Depreciation and Amortization).
- An increase of $2 million due to Pepco and DPL customer growth in 2013, primarily in the residential class.

The aggregate amount of these increases was partially offset by:

- A decrease of $13 million due to lower non-weather related average residential and commercial customer usage.
- A decrease of $8 million in transmission revenue primarily attributable to FERC formula rate true-ups.
- A decrease of $4 million in distribution revenue due to lower pass-through revenue (which is substantially offset by a corresponding decrease in Other Taxes) primarily the result of a decrease in sales that resulted in a decrease in Montgomery County, Maryland utility taxes that are collected by Pepco on behalf of the jurisdiction.
- A decrease of $3 million due to lower sales primarily as a result of milder weather during the 2013 summer months, as compared to 2012.
- A decrease of $2 million in transmission revenue primarily attributable to a peak-load rate decrease effective January 2013.

Default Electricity Supply

	2013	2012	Change
Default Electricity Supply Revenue			
Residential	$1,087	$1,171	$ (84)
Commercial and industrial	418	425	(7)
Other	115	85	30
Total Default Electricity Supply Revenue	$1,620	$1,681	$ (61)

Other Default Electricity Supply Revenue consists primarily of (i) revenue from the resale by ACE in the PJM RTO market of energy and capacity purchased under contracts with unaffiliated NUGs and (ii) revenue from transmission enhancement credits.

	2013	2012	Change
Default Electricity Supply Sales (GWh)			
Residential	10,696	11,256	(560)
Commercial and industrial	3,909	4,342	(433)
Other	42	41	1
Total Default Electricity Supply Sales	14,647	15,639	(992)

	2013	2012	Change
Default Electricity Supply Customers (in thousands)			
Residential	1,339	1,382	(43)
Commercial and industrial	125	130	(5)
Other	—	—	—
Total Default Electricity Supply Customers	1,464	1,512	(48)

Default Electricity Supply Revenue decreased by $61 million primarily due to:

- A decrease of $69 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A net decrease of $24 million due to lower non-weather related average customer usage in DPL and ACE, partially offset by higher Pepco customer usage.
- A decrease of $4 million due to lower sales primarily as a result of milder weather during the 2013 summer months, as compared to 2012.

The aggregate amount of these decreases was partially offset by:

- An increase of $27 million in wholesale energy and capacity resale revenues primarily due to higher market prices for the resale of electricity and capacity purchased from NUGs.
- A net increase of $5 million as a result of higher Pepco and ACE Default Electricity Supply rates, partially offset by lower DPL rates.
- An increase of $4 million due to higher Pepco revenue from transmission enhancement credits.

Regulated Gas

	2013	2012	Change
Regulated Gas Revenue			
Residential	$ 71	$ 63	$ 8
Commercial and industrial	35	32	3
Transportation and other	8	7	1
Total Regulated Gas Revenue	$ 114	$ 102	$ 12

	2013	2012	Change
Regulated Gas Sales (million cubic feet)			
Residential	5,365	4,052	1,313
Commercial and industrial	3,232	2,310	922
Transportation and other	5,141	4,877	264
Total Regulated Gas Sales	13,738	11,239	2,499

	2013	2012	Change
Regulated Gas Customers (in thousands)			
Residential	116	115	1
Commercial and industrial	9	9	—
Transportation and other	—	—	—
Total Regulated Gas Customers	125	124	1

Regulated Gas Revenue increased by $12 million primarily due to:

- An increase of $20 million due to higher sales primarily as a result of colder weather during the winter months of 2013 as compared to 2012.
- An increase of $4 million due to higher non-weather related average commercial customer usage.
- An increase of $4 million due to a revenue adjustment recorded in June 2012 for a reduction in the estimate of gas sold but not yet billed to customers (which is partially offset by an increase in Fuel and Purchased Energy).
- An increase of $1 million due to a distribution rate increase effective July 2013.

The aggregate amount of these increases was partially offset by a decrease of $18 million due to a GCR decrease effective November 2012.

Pepco Energy Services

Pepco Energy Services' operating revenue decreased by $51 million primarily due to:

- A decrease of $25 million due to decreased energy services construction activities.
- A decrease of $19 million due to lower generation and capacity revenues attributable to the deactivation of the remaining generating facilities in the second quarter of 2012.
- A decrease of $7 million due to a reduction in streetlight construction service and underground transmission construction activities.

<u>Operating Expenses</u>

Fuel and Purchased Energy and Other Services Cost of Sales

A detail of PHI's consolidated Fuel and Purchased Energy and Other Services Cost of Sales is as follows:

	2013	2012	Change
Power Delivery	$1,587	$1,647	$ (60)
Pepco Energy Services	113	146	(33)
Corporate and Other	(1)	(3)	2
Total	$1,699	$1,790	$ (91)

Power Delivery's Fuel and Purchased Energy consists of the cost of electricity and natural gas purchased by its utility subsidiaries to fulfill their respective Default Electricity Supply and Regulated Gas obligations and, as such, is recoverable from customers in accordance with the terms of public service commission orders. It also includes the cost of natural gas purchased for off-system sales. Fuel and Purchased Energy expense decreased by $60 million primarily due to:

- A decrease of $81 million primarily due to customer migration to competitive suppliers.

- A decrease of $28 million in deferred electricity expense primarily due to higher DPL Default Electricity Supply rates, which resulted in a lower rate of recovery of Default Electricity Supply costs.
- A decrease of $10 million from the settlement of financial hedges entered into as part of DPL's hedge program for the purchase of regulated natural gas.
- A decrease of $2 million due to lower electricity sales primarily as a result of milder weather during the 2013 summer months, as compared to 2012.

The aggregate amount of these decreases was partially offset by:

- A net increase of $31 million due to higher average electricity costs under Pepco and DPL Default Electricity Supply contracts, partially offset by lower ACE costs.
- An increase of $13 million in deferred electricity expense primarily due to a Renewable Portfolio Surcharge in Delaware effective June 2012 (which is substantially offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $9 million in the cost of gas purchases for on-system sales as a result of higher average gas prices.
- An increase of $5 million in Renewable Energy Credits in Delaware (which is offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $4 million in the cost of gas purchases for on-system sales as a result of an adjustment recorded in June 2012 for a reduction in the estimate of gas sold but not yet billed to customers (which is offset by an increase in Regulated Gas Revenue).

Pepco Energy Services

Pepco Energy Services' Fuel and Purchased Energy and Other Services Cost of Sales decreased by $33 million primarily due to:

- A decrease of $19 million primarily due to lower energy services construction activity.
- A decrease of $7 million due to lower purchases of fuel attributable to the deactivation of the remaining generating facilities in the second quarter of 2012.
- A decrease of $6 million associated with the reduction in streetlight construction service and underground transmission construction activities.

Other Operation and Maintenance

A detail of PHI's Other Operation and Maintenance expense is as follows:

	2013	2012	Change
Power Delivery	$661	$671	$ (10)
Pepco Energy Services	33	45	(12)
Corporate and Other	(47)	(48)	1
Total	$647	$668	$ (21)

Power Delivery

Other Operation and Maintenance expense for Power Delivery decreased by $10 million primarily due to:

- A decrease of $9 million in customer service costs.
- A decrease of $9 million associated with lower maintenance costs.
- A decrease of $8 million in other storm restoration costs.

The aggregate amount of these decreases was partially offset by:

- An increase of $6 million resulting from a 2012 deferred cost adjustment associated with DPL Default Electricity Supply. The deferred cost adjustments were primarily due to the under-recognition of allowed returns on net uncollectible expense and regulatory taxes in 2012.
- An increase of $4 million primarily due to 2012 total incremental storm restoration costs for major storm events as described in the following table:

	2013	2012	Change
Regulatory asset established for future recovery of January 2011 winter storm costs	$ —	$ (9)	$ 9
Costs associated with derecho storm (June 2012)	—	40	(40)
Regulatory asset established for future recovery of derecho storm costs	—	(35)	35
Total incremental major storm restoration costs	$ —	$ (4)	$ 4

  - In January 2011, Pepco incurred incremental storm restoration costs of $10 million associated with a severe winter storm, all of which were expensed in 2011. In July 2012, the MPSC issued an order allowing for the deferral and recovery of $9 million of such costs.
  - In the second and third quarters of 2012, Pepco, DPL and ACE incurred incremental storm restoration costs of $40 million associated with the June 2012 derecho which resulted in widespread damage to the electric distribution system in each of their service territories. PHI's utility subsidiaries deferred $35 million of these costs as regulatory assets to reflect the probable recovery of these storm restoration costs in Maryland and New Jersey. The MPSC approved the recovery of these costs in Maryland for both Pepco and DPL in its July and August 2013 rate orders, respectively, over a five-year period. ACE's stipulation of settlement approved by NJBPU in June 2013 provides for recovery of these costs in New Jersey over a three-year period. The remaining costs of $5 million relate to repair work completed in Delaware and the District of Columbia, which costs are not currently deferrable in those jurisdictions.
- An increase of $3 million associated with the write-off of disallowed MAPP and associated transmission projects costs.
- An increase of $2 million in environmental remediation costs.

Pepco Energy Services

Other Operation and Maintenance expense for Pepco Energy Services decreased by $12 million primarily due to:

- A decrease of $6 million in personnel costs in its energy savings services business primarily due to a reduction in the number of employees in the second half of 2012.
- A decrease of $4 million associated with the deactivation of its generating facilities in the second quarter of 2012.
- A decrease of $1 million for lower operating, repair and maintenance expenses at its combined heat and power operations in Atlantic City.
- A decrease of $1 million associated with an accrual for an energy savings guarantee shortfall in 2012.

Depreciation and Amortization

Depreciation and Amortization expense increased by $9 million to $352 million in 2013 from $343 million in 2012 primarily due to:

- An increase of $12 million in amortization of regulatory assets primarily related to recoverable AMI costs, major storm costs and rate case costs.
- An increase of $10 million in amortization of MAPP abandoned costs (which is offset in Regulated T&D Electric Revenue).
- An increase of $2 million in amortization of stranded costs primarily as the result of higher revenue due to higher sales for the ACE Transition Bond Charge and Market Transition Charge Tax (revenue ACE receives and pays to ACE Funding to recover income taxes associated with Transition Bond Charge revenue), which is partially offset in Default Electricity Supply Revenue.

The aggregate amount of these increases was partially offset by:

- A decrease of $8 million primarily due to the deactivation of Pepco Energy Services generating facilities in the second quarter of 2012.
- A decrease of $6 million in the Delaware Renewable Energy Portfolio Standards deferral (which is substantially offset by a corresponding decrease in Regulated T&D Electric Revenue).
- A decrease of $3 million due to lower depreciation rates, partially offset by utility plant additions.

Other Taxes

Other Taxes decreased by $5 million to $325 million in 2013 from $330 million in 2012. The decrease was primarily due to lower sales that resulted in a decrease in utility taxes that are collected and passed through by Power Delivery (substantially offset by a corresponding decrease in Regulated T&D Electric Revenue).

Deferred Electric Service Costs

Deferred Electric Service Costs, which relate only to ACE, represent (i) the over or under recovery of electricity costs incurred by ACE to fulfill its Default Electricity Supply obligation and (ii) the over or under recovery of New Jersey Societal Benefit Program costs incurred by ACE. The cost of electricity purchased is reported under Fuel and Purchased Energy and the corresponding revenue is reported under Default Electricity Supply Revenue. The cost of New Jersey Societal Benefit Programs is reported under Other Operation and Maintenance and the corresponding revenue is reported under Regulated T&D Electric Revenue.

Deferred Electric Service Costs increased by $45 million to an expense of $39 million in 2013 as compared to an expense reduction of $6 million in 2012 primarily due to an increase in deferred electricity expense as a result of higher Default Electricity Supply and New Jersey Societal Benefit Programs revenue rates and lower electricity supply costs.

Impairment Losses

PHI's operating expenses include impairment losses of $5 million pre-tax ($3 million after-tax) for the nine months ended September 30, 2012, associated primarily with Pepco Energy Services' investment in a landfill gas-fired electric generation facility and combustion turbines at the Buzzard Point generation facility.

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $18 million to a net expense of $181 million in 2013 from a net expense of $163 million in 2012. The increase reflects a $15 million increase in interest expense primarily associated with higher long-term debt and $3 million associated with lower income related to AFUDC that is applied to capital projects.

Income Tax Expense

PHI's income tax expense increased by $188 million to $280 million in 2013 from $92 million in 2012. PHI's consolidated effective tax rates for the nine months ended September 30, 2013 and 2012 were 84.3% and 33.3%, respectively.

The increase in the effective tax rate for the nine months ended September 30, 2013 occurred as a result of recording $55 million of changes in estimates and interest related to uncertain and effectively settled tax positions in the first quarter of 2013. In addition, the increase in the effective tax rate resulted from the establishment of valuation allowances of $101 million in the first quarter of 2013 against certain deferred tax assets in Corporate and Other. Between 1990 and 1999, PCI, through various subsidiaries, entered into certain transactions involving investments in aircraft and aircraft equipment, railcars and other assets. In connection with these transactions, PCI recorded deferred tax assets in prior years of $101 million in the aggregate. Following events that took place during the first quarter of 2013, which included (i) court decisions in favor of the IRS with respect to both Consolidated Edison's cross-border lease transaction (as discussed in Note (16), "Discontinued Operations – Cross-Border Energy Lease Investments," to the consolidated financial statements of PHI included herein) and another taxpayer's structured transactions, (ii) the change in PHI's tax position with respect to the tax benefits associated with its cross-border energy leases, and (iii) PHI's decision in March 2013 to begin to pursue the early termination of its remaining cross-border energy lease investments (which represented a substantial portion of the remaining assets within PCI) without the intent to reinvest these proceeds in income-producing assets, management evaluated the likelihood that PCI will be able to realize the $101 million of deferred tax assets in the future. Based on this evaluation, PCI established valuation allowances against these deferred tax assets totaling $101 million in the first quarter of 2013.

In 2012, PHI recorded tax benefits of $10 million for changes in estimates and interest related to uncertain and effectively settled tax positions primarily due to the effective settlement with the IRS in the first quarter of 2012 with respect to the methodology used historically to calculate deductible mixed service costs and the expiration of the statute of limitations associated with an uncertain tax position in Pepco.

Discontinued Operations

PHI's (loss) income from discontinued operations, net of income taxes, is comprised of the following:

	2013	2012	Change
Cross-border energy lease investments	$(327)	$33	$ (360)
Pepco Energy Services' retail electric and natural gas supply businesses	5	25	(20)
(Loss) income from discontinued operations, net of income taxes	$(322)	$58	$ (380)

For the nine months ended September 30, 2013 and 2012, income from discontinued operations, net of income taxes, was a loss of $322 million and income of $58 million, respectively. The decrease of $380 million is comprised of a decrease of $360 million related to PHI's cross-border lease investments and a decrease of $20 million related to the retail electric and natural gas supply businesses at Pepco Energy Services.

The decrease in income from discontinued operations, net of income taxes, for PHI's cross-border energy lease investments is primarily due to after-tax non-cash charges of $323 million recorded in the first quarter of 2013 and $6 million in the second quarter of 2013, each related to a change in assessment regarding the tax benefits related to the cross-border energy lease investments and consisting of a $373 million pre-tax non-cash charge ($313 million after-tax) to reduce the carrying value of the investments and a $16 million after-tax non-cash charge to reflect the anticipated additional interest expense related to the change in PCI's estimated federal and state income tax obligations as if it were a separate taxpayer. The net income from discontinued operations, net of income taxes, was reduced further by lower cross-border energy lease investment earnings as a result of holding fewer cross-border lease investments in 2013, the loss recorded on the early termination of the remaining cross-border energy lease investments during 2013, and gains recorded on the early termination of certain leases within the cross-border energy lease portfolio in the third quarter of 2012.

The decrease in income from discontinued operations, net of income taxes, at Pepco Energy Services is due to a reduction in sales volume associated with the wind-down of the retail electric and natural gas supply businesses, a reduction in mark-to-market gains, and costs incurred to accelerate the wind-down of the retail electric supply business.

Capital Resources and Liquidity

This section discusses PHI's working capital, cash flow activity, capital requirements and other uses and sources of capital.

Working Capital

At September 30, 2013, PHI's current assets on a consolidated basis totaled $1.5 billion and its consolidated current liabilities totaled $2.4 billion, resulting in a working capital deficit of $0.9 billion. PHI expects the working capital deficit at September 30, 2013 to be funded during 2013 in part through cash flows from operations and from the issuance of long-term debt. At December 31, 2012, PHI's current assets on a consolidated basis totaled $1.3 billion and its current liabilities totaled $2.5 billion, for a working capital deficit of $1.2 billion. The decrease of $371 million in the working capital deficit from December 31, 2012 to September 30, 2013 was primarily due to a decrease in short-term debt, the repayment of which was primarily funded with cash received from the early terminations of the cross-border energy leases, and an increase in income taxes receivable, partially offset by an increase in liabilities and accrued interest related to uncertain tax positions.

At September 30, 2013, PHI's consolidated cash and cash equivalents totaled $58 million, which consisted of cash and temporary cash investments, but excluded current Restricted Cash Equivalents (cash that is available to be used only for designated purposes) that totaled $15 million. At December 31, 2012, PHI's consolidated cash and cash equivalents totaled $25 million, which consisted of cash and uncollected funds but excluded current Restricted Cash Equivalents that totaled $10 million.

A detail of PHI's short-term debt balance and current maturities of long-term debt and project funding balance is as follows:

	As of September 30, 2013 (millions of dollars)							
Type	PHI Parent	Pepco	DPL	ACE	ACE Funding	Pepco Energy Services	PCI	PHI Consolidated
Variable Rate Demand Bonds	$ —	$ —	$ 105	$ 18	$ —	$ —	$ —	$ 123
Commercial Paper	—	32	150	99	—	—	—	281
Total Short-Term Debt	$ —	$ 32	$ 255	$ 117	$ —	$ —	$ —	$ 404
Current Portion of Long-Term Debt and Project Funding	$ —	$ 375	$ 250	$ 7	$ 41	$ 11	$ 11	$ 695

	As of December 31, 2012 (millions of dollars)						
Type	PHI Parent	Pepco	DPL	ACE	ACE Funding	Pepco Energy Services	PHI Consolidated
Variable Rate Demand Bonds	$ —	$ —	$ 105	$ 23	$ —	$ —	$ 128
Commercial Paper	264	231	32	110	—	—	637
Term Loan Agreement	200	—	—	—	—	—	200
Total Short-Term Debt	$ 464	$ 231	$ 137	$ 133	$ —	$ —	$ 965
Current Portion of Long-Term Debt and Project Funding	$ —	$ 200	$ 250	$ 69	$ 39	$ 11	$ 569

Commercial Paper

PHI, Pepco, DPL and ACE maintain commercial paper programs to address short-term liquidity needs. As of September 30, 2013, the maximum capacity available under these programs was $875 million, $500 million, $500 million and $250 million, respectively, subject to available borrowing capacity under the credit facility.

Pepco, DPL and ACE had $32 million, $150 million and $99 million, respectively, of commercial paper outstanding at September 30, 2013. PHI had no commercial paper outstanding as of September 30, 2013. The weighted average interest rate for commercial paper issued by PHI, Pepco, DPL and ACE during the nine months ended September 30, 2013 was 0.70%, 0.37%, 0.29% and 0.32%, respectively. The weighted average maturity of all commercial paper issued by PHI, Pepco, DPL and ACE during the nine months ended September 30, 2013 was five, six, three and four days, respectively.

Financing Activity During the Three Months Ended September 30, 2013

Bond Payments

In July 2013, ACE Funding made principal payments of $7 million on its Series 2002-1 Bonds, Class A-3, and $2 million on its Series 2003-1 Bonds, Class A-2.

Bond Retirement

On August 1, 2013, ACE repaid at maturity $68.6 million of its 6.625% non-callable first mortgage bonds.

Equity Forward Transaction

During 2012, PHI entered into an equity forward transaction in connection with a public offering of PHI common stock. Pursuant to the terms of this transaction, a forward counterparty borrowed 17,922,077 shares of PHI's common stock from third parties and sold them to a group of underwriters for $19.25 per share, less an underwriting discount equal to $0.67375 per share. Under the terms of the equity forward transaction, upon physical settlement thereof, PHI was required to issue and deliver shares of PHI common stock to the forward counterparty at the then applicable forward sale price. The forward sale price was initially determined to be $18.57625 per share at the time the equity forward transaction was entered into and was subject to reduction from time to time in accordance with the terms of the equity forward transaction. PHI believed that the equity forward transaction substantially eliminated future equity price risk because the forward sale price was determinable as of the date that PHI entered into the equity forward transaction and was only reduced pursuant to the contractual terms of the equity forward transaction through the settlement date, which reductions were not affected by a future change in the market price of the PHI common stock. On February 27, 2013, PHI physically settled the equity forward at the then applicable forward sale price of $17.39 per share. The proceeds of approximately $312 million were used to repay outstanding commercial paper, a portion of which had been issued in order to make capital contributions to the utilities, and for general corporate purposes.

Credit Facility

PHI, Pepco, DPL and ACE maintain an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. On August 1, 2011, PHI, Pepco, DPL and ACE entered into an amended and restated credit agreement which, on August 2, 2012, was amended to extend the term of the credit facility to August 1, 2017 and to amend the pricing schedule to decrease certain fees and interest rates payable to the lenders under the facility. On June 6, 2013, as permitted under the existing terms of the credit agreement, PHI, Pepco, DPL and ACE provided to the agent and lenders under the credit agreement, a notice requesting a one-year extension of the credit facility termination date. The request was approved and the new termination date is August 1, 2018. All of the terms and conditions as well as pricing remain the same.

The aggregate borrowing limit under the amended and restated credit facility is $1.5 billion, all or any portion of which may be used to obtain loans and up to $500 million of which may be used to obtain letters of credit. The facility also includes a swingline loan sub-facility, pursuant to which each company may make same day borrowings in an aggregate amount not to exceed 10% of the total amount of the facility. Any swingline loan must be repaid by the borrower within fourteen days of receipt. The credit sublimit is $750 million for PHI and $250 million for each of Pepco, DPL and ACE. The sublimits may be increased or decreased by the individual borrower during the term of the facility, except that (i) the sum of all of the borrower sublimits following any such increase or decrease must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by (a) PHI may not exceed $1.25 billion, and (b) each of Pepco, DPL or ACE may not exceed the lesser of $500 million or the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the sublimit reallocations may not exceed eight per year during the term of the facility.

For additional discussion of the Credit Facility, see Note (9), "Debt," to the consolidated financial statements of PHI.

Cash and Credit Facility Available as of September 30, 2013

	Consolidated PHI	PHI Parent	Utility Subsidiaries
		(millions of dollars)	
Credit Facility (Total Capacity)	$ 1,500	$ 750	$ 750
Less: Letters of Credit issued	2	2	—
Commercial Paper outstanding	281	—	281
Remaining Credit Facility Available	1,217	748	469
Cash Invested in Money Market Funds and on hand (a)	39	37	2
Total Cash and Credit Facility Available	$ 1,256	$ 785	$ 471

(a) Cash and Cash Equivalents reported on the PHI consolidated balance sheet totaled $58 million, of which $39 million was invested in money market funds, and the balance was held in cash and uncollected funds.

Financing Activities Subsequent to September 30, 2013

Bond Payments

In October 2013, ACE Funding made principal payments of $8 million on its Series 2002-1 Bonds, Class A-3, and $3 million on its Series 2003-1 Bonds, Class A-2.

Long-Term Project Funding

On October 24, 2013, Pepco Energy Services entered into an agreement with a lender to receive up to $8 million in construction financing at an interest rate of 4.68% for an energy savings project that is expected to be completed in 2014. The agreement includes a transfer of receivables from Pepco Energy Services to the lender after construction is completed, under which the customer would make contractual payments over a 23-year period to repay the financing. If there are shortfalls in Pepco Energy Services' energy savings guarantee or other performance obligations to the customer that reduce customer payments below the contractual payment amounts, then Pepco Energy Services would compensate the lender for the unpaid amounts. PHI has guaranteed the performance obligations of Pepco Energy Services under the financing agreement.

PHI's Cross-Border Energy Lease Investments

PHI has an ongoing dispute with the IRS regarding the appropriateness of certain significant income tax benefits claimed by PHI related to its cross-border energy lease investments beginning with its 2001 federal income tax return. In the first quarter of 2013, PHI estimated that, in the event the IRS were to be fully successful in its challenge to PHI's tax position on the cross-border energy leases, PHI would have been obligated to pay $192 million in additional federal taxes and $50 million of interest on the additional federal taxes, totaling $242 million as of March 31, 2013. The estimate of additional federal taxes due includes PHI's estimate of the expected resolution of other uncertain and effectively settled tax positions unrelated to the leases, the carrying back or carrying forward of any existing net operating losses, and the application of certain amounts paid in advance to the IRS.

In order to mitigate PHI's ongoing interest costs associated with the $242 million estimate of additional taxes and interest, PHI made a $242 million advanced payment to the IRS for the estimated additional taxes and related interest in the first quarter of 2013. This advanced payment was funded from then currently available sources of liquidity and short-term borrowings. In March 2013, PHI began to pursue the early termination of its six remaining cross-border energy lease investments, which had a net carrying value of approximately $869 million as of March 31, 2013. During the second and third quarters of 2013, PHI terminated early all of its interests in the six remaining lease investments. PHI received aggregate net cash proceeds of $873 million (net of aggregate termination payments of $2.0 billion used to retire the non-recourse debt associated with the terminated leases) and recorded an aggregate pre-tax loss, including transaction costs, of approximately $3 million ($2 million after-tax), representing the excess of the carrying value of the terminated leases over the net cash proceeds received. A portion of the net cash proceeds from the terminated leases was used to repay borrowings utilized to fund the advanced payment discussed above.

Pension and Postretirement Benefit Plans

Pension benefits are provided under PHI's non-contributory retirement plan (the PHI Retirement Plan), a defined benefit pension plan that covers substantially all employees of Pepco, DPL and ACE and certain employees of other PHI subsidiaries. PHI's funding policy with regard to the PHI Retirement Plan is to maintain a funding level that is at least equal to the target liability as defined under the Pension Protection Act of 2006.

PHI satisfied the minimum required contribution rules under the Pension Protection Act in 2012 and 2011, and anticipates that it will satisfy the requirement in 2013. In the first quarter of 2013, PHI, DPL and ACE made discretionary tax-deductible contributions to the PHI Retirement Plan in the amounts of $20 million, $10 million and $30 million, respectively. PHI made an additional discretionary tax-deductible contribution to the PHI Retirement Plan of approximately $60 million during the second quarter of 2013. In the first quarter of 2012, Pepco, DPL and ACE made discretionary tax-deductible contributions to the PHI Retirement Plan in the amounts of $85 million, $85 million and $30 million, respectively, which brought the PHI Retirement Plan assets to at least the funding target level for 2012 under the Pension Protection Act.

Based on the results of the 2012 actuarial valuation, PHI's net periodic pension and other postretirement benefit costs were $110 million in 2012 versus $94 million in 2011. The current estimate of benefit cost for 2013 is $94 million. The utility subsidiaries are responsible for substantially all of the total PHI net periodic pension and other postretirement benefit costs. Approximately 30% of net periodic pension and other postretirement benefit costs are capitalized. PHI estimates that its net periodic pension and other postretirement benefit expense will be approximately $66 million in 2013, as compared to $77 million in 2012.

Other Postretirement Benefit Plan Amendment

During 2013, PHI approved two amendments to its other postretirement benefits plan. These amendments impacted the retiree medical plan and the retiree life insurance benefits, and will be effective on January 1, 2014. As a result of the amendments, which were cumulatively significant, PHI remeasured its projected benefit obligation for other postretirement benefits as of July 1, 2013. The remeasurement resulted in a $193 million reduction of the projected benefit obligation, which included recording a prior service credit of $124 million, which will be amortized over approximately ten years, and a $69 million reduction from a change in the discount rate from 4.10% as of December 31, 2012 to 4.95% as of July 1, 2013. The remeasurement is expected to result in a $13 million reduction in net periodic benefit cost for other postretirement benefits during 2013. Approximately 30% of net periodic other postretirement benefit costs are capitalized.

Cash Flow Activity

PHI's cash flows for the nine months ended September 30, 2013 and 2012 are summarized below:

	Cash Source (Use)		
	2013	**2012**	**Change**
	(millions of dollars)		
Operating Activities	$ 267	$ 419	$ (152)
Investing Activities	(55)	(662)	607
Financing Activities	(179)	248	(427)
Net increase in cash and cash equivalents	$ 33	$ 5	$ 28

Operating Activities

Cash flows from operating activities during the nine months ended September 30, 2013 and 2012 are summarized below:

	Cash Source (Use)		
	2013	2012	Change
	(millions of dollars)		
Net income from continuing operations	$ 52	$ 184	$ (132)
Non-cash adjustments to net income	343	337	6
Pension contributions	(120)	(200)	80
Advanced payment made to taxing authority	(242)	—	(242)
Changes in cash collateral related to derivative activities	28	76	(48)
Changes in other assets and liabilities	166	43	123
Changes in net current assets held for disposition	40	(21)	61
Net cash from operating activities	$ 267	$ 419	$ (152)

Net cash from operating activities decreased $152 million for the nine months ended September 30, 2013, compared to the same period in 2012. The decrease was primarily due to a decrease in net income of $132 million and a $242 million advanced payment to the IRS for estimated additional taxes and related interest. These decreases were partially offset by an $80 million decrease in pension contributions and a $61 million increase in net assets held for disposition associated with the early termination of all cross-border energy lease investments and the wind-down of Pepco Energy Services' retail electric and natural gas supply businesses.

Investing Activities

Cash flows used by investing activities during the nine months ended September 30, 2013 and 2012 are summarized below:

	Cash (Use) Source		
	2013	2012	Change
	(millions of dollars)		
Investment in property, plant and equipment	$(943)	$(888)	$ (55)
Department of Energy (DOE) capital reimbursement awards received	17	25	(8)
Changes in restricted cash equivalents	(2)	(2)	—
Net other investing activities	—	1	(1)
Proceeds from disposal of assets held for disposition	873	202	671
Net cash used by investing activities	$ (55)	$(662)	$ 607

Net cash used by investing activities decreased $607 million for the nine months ended September 30, 2013, compared to the same period in 2012. The decrease in net cash used was primarily due to an increase of $671 million in proceeds from the early termination of cross-border lease investments.

Financing Activities

Cash flows from financing activities during the nine months ended September 30, 2013 and 2012 are summarized below:

	Cash (Use) Source		
	2013	2012	Change
	(millions of dollars)		
Dividends paid on common stock	$(201)	$(185)	$ (16)
Common stock issued for the Dividend Reinvestment Plan and employee-related compensation	38	40	(2)
Issuances of common stock	324	—	324
Issuances of long-term debt	350	450	(100)
Reacquisitions of long-term debt	(96)	(165)	69
Repayments of short-term debt, net	(361)	(84)	(277)
Issuances of term loans	250	200	50
Repayments of term loans	(450)	—	(450)
Cost of issuances	(17)	(8)	(9)
Net other financing activities	(16)	—	(16)
Net cash (used by) from financing activities	$(179)	$ 248	$ (427)

Net cash from financing activities decreased $427 million for the nine months ended September 30, 2013, compared to the same period in 2012. The decrease was primarily due to a decrease of $400 million in term loans and an increase of $277 million of short-term debt repayments, offset by $324 million in cash received from issuances of common stock, primarily due to the settlement of the equity forward transaction.

Changes in Outstanding Long-Term Debt

Cash flows from the issuances and reacquisitions of long-term debt for the nine months ended September 30, 2013 and 2012 are summarized below:

	Issuances	
	2013	2012
	(millions of dollars)	
Pepco		
4.15% First mortgage bonds due 2043	$ 250	$ —
3.05% First mortgage bonds due 2022	—	200
	250	200
DPL		
4.00% First mortgage bonds due 2042	—	250
	—	250
ACE		
Term loan due 2014	100	—
	100	—
	$ 350	$ 450

	Reacquisitions 2013	Reacquisitions 2012
	(millions of dollars)	
Pepco		
5.375% Tax-exempt bonds due 2024(a)	$ —	$ 38
	—	38
DPL		
0.75% Tax-exempt bonds due 2026(a)	—	35
1.80% Tax-exempt bonds due 2025	—	15
2.30% Tax-exempt bonds due 2028	—	16
5.20% Tax-exempt bonds due 2019	—	31
	—	97
ACE		
Securitization bonds due 2012-2013	28	26
5.60% Tax-exempt bonds due 2025(a)	—	4
6.625% Tax-exempt bonds due 2013	68	—
	96	30
	$ 96	$ 165

(a) These bonds were secured by an outstanding series of collateral first mortgage bonds issued by the utility, which had maturity dates, optional and mandatory redemption provisions, interest rates and interest payment dates that are identical to the terms of the tax-exempt bonds. The collateral first mortgage bonds were automatically redeemed simultaneously with the redemption of the tax-exempt bonds.

Changes in Short-Term Debt

As of September 30, 2013, Pepco, DPL and ACE had a total of $281 million of commercial paper outstanding as compared to $637 million of commercial paper outstanding as of December 31, 2012. PHI had no commercial paper outstanding as of September 30, 2013.

On March 28, 2013, PHI entered into a $250 million term loan agreement, pursuant to which PHI had borrowed (and was not permitted to re-borrow) $250 million. PHI used the net proceeds of the loan under the loan agreement to repay the outstanding $200 million term loan made in 2012, and for general corporate purposes. On May 29, 2013, PHI repaid the $250 million term loan with a portion of the net proceeds from the early termination of the cross-border energy lease investments.

Capital Requirements

Capital Expenditures

Pepco Holdings' capital expenditures for the nine months ended September 30, 2013 were $943 million, of which $403 million was incurred by Pepco, $249 million was incurred by DPL, $204 million was incurred by ACE, $2 million was incurred by Pepco Energy Services and $85 million was incurred by Corporate and Other. The Power Delivery expenditures were primarily related to capital costs associated with new customer services, distribution reliability and transmission. Corporate and Other capital expenditures primarily consisted of hardware and software expenditures that will be allocated to Power Delivery when the assets are placed in service.

PHI's projected capital expenditures for the Power Delivery business for the five-year period from 2014 through 2018 are summarized below. PHI expects to fund these expenditures through internally generated cash and external financing.

	For the Year Ended December 31,					
	2014	2015	2016	2017	2018	Total
			(millions of dollars)			
Power Delivery						
Distribution	$ 774	$ 707	$ 771	$ 729	$ 744	$3,725
Distribution – Smart Grid (AMI)	2	—	—	—	8	10
Transmission	318	290	260	255	285	1,408
Gas Delivery	29	28	28	28	29	142
Other	167	102	99	96	65	529
Total for Power Delivery Business	$1,290	$1,127	$1,158	$1,108	$1,131	$5,814

DOE Capital Reimbursement Awards

In 2009, the DOE announced awards under the American Recovery and Reinvestment Act of 2009 of:

- $105 million and $44 million in Pepco's Maryland and District of Columbia service territories, respectively, for the implementation of an AMI system, direct load control, distribution automation, and communications infrastructure.
- $19 million in ACE's New Jersey service territory for the implementation of an AMI system, direct load control, distribution automation, and communications infrastructure.

During 2010, Pepco, ACE and the DOE signed agreements formalizing the $168 million in awards. Of the $168 million, $130 million is being used for the smart grid and other capital expenditures of Pepco and ACE. The remaining $38 million is being used to offset incremental expenses associated with direct load control and other Pepco and ACE programs. During the nine months ended September 30, 2013, Pepco and ACE received award payments of $24 million and $3 million, respectively. The cumulative award payments received by Pepco and ACE as of September 30, 2013 were $139 million and $16 million, respectively.

The IRS has announced that, to the extent these grants are expended on capital items, they will not be considered taxable income.

Guarantees, Indemnifications, Obligations and Off-Balance Sheet Arrangements

For a discussion of PHI's third party guarantees, indemnifications, obligations and off-balance sheet arrangements, see Note (14), "Commitments and Contingencies," to the consolidated financial statements of PHI.

PHI guarantees the obligations of Pepco Energy Services under certain of its energy savings performance, combined heat and power and construction contracts. At September 30, 2013, PHI's guarantees of Pepco Energy Services' obligations under these contracts totaled $186 million. PHI also guarantees the obligations of Pepco Energy Services under surety bonds obtained by Pepco Energy Services for construction projects. These guarantees totaled $219 million at September 30, 2013.

In addition, PHI guarantees certain obligations of Pepco, DPL and ACE under surety bonds obtained by these subsidiaries, for construction projects and self-insured workers compensation matters. These guarantees totaled $29 million at September 30, 2013.

Dividends

On October 24, 2013, Pepco Holdings' Board of Directors declared a dividend on common stock of 27 cents per share payable December 31, 2013 to stockholders of record on December 10, 2013. PHI had approximately $606 million and $1,077 million of retained earnings free of restrictions at September 30, 2013 and December 31, 2012, respectively.

Contractual Arrangements with Credit Rating Triggers or Margining Rights

Under certain contractual arrangements entered into by PHI's subsidiaries, the subsidiary may be required to provide cash collateral or letters of credit as security for its contractual obligations if the credit ratings of PHI or the subsidiary are downgraded. In the event of a downgrade, the amount required to be posted would depend on the amount of the underlying contractual obligation existing at the time of the downgrade. Based on contractual provisions in effect at September 30, 2013, a downgrade in the unsecured debt credit ratings of PHI and each of its rated subsidiaries to below “investment grade” would increase the collateral obligation of PHI and its subsidiaries by up to $94 million. This amount is attributable primarily to energy services contracts and accounts payable to independent system operators and distribution companies. PHI believes that it and its subsidiaries currently have sufficient liquidity to fund their operations and meet their financial obligations.

Many of the contractual arrangements entered into by PHI’s subsidiaries in connection with Default Electricity Supply activities include margining rights pursuant to which the PHI subsidiary or a counterparty may request collateral if the market value of the contractual obligations reaches levels in excess of the credit thresholds established in the applicable arrangements. Pursuant to these margining rights, the affected PHI subsidiary may receive, or be required to post, collateral due to energy price movements. PHI believes that it and its subsidiaries currently have sufficient liquidity to fund their operations and meet their financial obligations.

Regulatory and Other Matters

MPSC New Generation Contract Requirement

In September 2009, the MPSC initiated an investigation into whether Maryland electric distribution companies (EDCs) should be required to enter into long-term contracts with entities that construct, acquire or lease, and operate, new electric generation facilities in Maryland.

In April 2012, the MPSC issued an order determining that there is a need for one new power plant in the range of 650 to 700 MW beginning in 2015. The order requires Pepco, DPL and BGE (collectively, the Contract EDCs) to negotiate and enter into a contract with the winning bidder of a competitive bidding process in amounts proportional to their relative SOS loads. Under the contract, the winning bidder will construct a 661 MW natural gas-fired combined cycle generation plant in Waldorf, Maryland, with an expected commercial operation date of June 1, 2015. The order acknowledged the Contract EDCs’ concerns about the requirements of the contract and directed them to negotiate with the winning bidder and submit any proposed changes in the contract to the MPSC for approval. The order further specified that the Contract EDCs will recover the associated costs through surcharges on their respective SOS customers.

In April 2012, a group of generating companies operating in the PJM region filed a complaint in the U.S. District Court for the District of Maryland challenging the MPSC’s order on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. In May 2012, the Contract EDCs and other parties filed notices of appeal in circuit courts in Maryland requesting judicial review of the MPSC’s order. These circuit court appeals were consolidated in the Circuit Court for Baltimore City.

On April 16, 2013, the MPSC issued an order approving a final form of the contract and directing the Contract EDCs to enter into the contract with the winning bidder in amounts proportional to their relative SOS loads. On June 4, 2013, Pepco and DPL each entered into identical contracts in accordance with the terms of the MPSC’s order; however, under each contract’s own terms, it will not become effective, if at all, until all legal proceedings related to these contracts and the actions of the MPSC in the related proceeding have been resolved.

On September 30, 2013, the U.S. District Court for the District of Maryland issued a ruling that the MPSC’s April 2012 order violated the Supremacy Clause of the U.S. Constitution by attempting to regulate wholesale prices. In contrast, on October 1, 2013, the Maryland Circuit Court for Baltimore City upheld the MPSC’s orders requiring the Contract EDCs to enter into the contracts.

On October 24, 2013, the Federal district court issued an order ruling that the contracts are illegal and unenforceable. This Federal district court order and its associated ruling could impact the state circuit court appeal, to which the Contract EDCs are parties, although such impact, if any, cannot be determined at this time. PHI expects the Federal district court decision to be appealed. The Contract EDCs also will likely appeal the state court decision to the Maryland Court of Special Appeals.

Assuming the contracts, as currently written, were to become effective by the expected commercial operation date of June 1, 2015, PHI continues to believe that Pepco and DPL may be required to account for their proportional share of the contract as a derivative instrument at fair value with an offsetting regulatory asset because they would recover any payments under the contract from SOS customers. In such event, PHI estimates that Pepco and DPL would be required to record an aggregate derivative liability ranging from $55 million to $70 million with an offsetting regulatory asset in a like amount. This estimated range and related assumptions may change prior to the time that the contracts become effective, if at all. PHI, Pepco and DPL have concluded that any accounting for these contracts would not be required until all legal proceedings related to these contracts and the actions of the MPSC in the related proceeding have been resolved.

PHI, Pepco and DPL are evaluating these proceedings to determine (i) the extent of the negative effect that the contract for new generation may have on PHI's, Pepco's and DPL's respective credit metrics, as calculated by independent rating agencies that evaluate and rate PHI, Pepco and DPL and each of their debt issuances, (ii) the effect on Pepco's and DPL's ability to recover their associated costs of the contract for new generation if a significant number of SOS customers elect to buy their energy from alternative energy suppliers, and (iii) the effect of the contract on the financial condition, results of operations and cash flows of each of PHI, Pepco and DPL.

For a discussion of other regulatory matters, see Note (7), "Regulatory Matters," to the consolidated financial statements of PHI.

Legal Proceedings

For a discussion of legal proceedings, see Note (14), "Commitments and Contingencies," to the consolidated financial statements of PHI.

Critical Accounting Policies

For a discussion of Pepco Holdings' critical accounting policies, please refer to Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Pepco Holdings' 2012 Form 10-K. There have been no material changes to PHI's critical accounting policies as disclosed in the 2012 Form 10-K.

New Accounting Standards and Pronouncements

For information concerning new accounting standards and pronouncements that have recently been adopted by PHI and its subsidiaries or that one or more of the companies will be required to adopt on or before a specified date in the future, see Note (3), "Newly Adopted Accounting Standards," and Note (4), "Recently Issued Accounting Standards, Not Yet Adopted," to the consolidated financial statements of PHI.

MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Potomac Electric Power Company

Pepco meets the conditions set forth in General Instruction H(1)(a) and (b) to the Form 10-Q, and accordingly information otherwise required under this Item has been omitted in accordance with General Instruction H(2) to Form 10-Q.

General Overview

Pepco is engaged in the transmission and distribution of electricity in the District of Columbia and significant portions of Prince George’s County and Montgomery County in suburban Maryland. Pepco also provides Default Electricity Supply. Pepco’s service territory covers approximately 640 square miles and has a population of approximately 2.2 million. As of September 30, 2013, approximately 57% of delivered electricity sales were to Maryland customers and approximately 43% were to District of Columbia customers.

Pepco’s results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of Pepco in Maryland and in the District of Columbia, revenue is not affected by unseasonably warmer or colder weather because a BSA for retail customers was implemented that provides for a fixed distribution charge per customer rather than a charge based on energy usage. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland and the District of Columbia to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. Changes in customer usage (due to weather conditions, energy prices, energy savings programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

In accounting for the BSA in Maryland and the District of Columbia, a Revenue Decoupling Adjustment is recorded representing either (i) a positive adjustment equal to the amount by which revenue from Maryland and District of Columbia retail distribution sales falls short of the revenue that Pepco is entitled to earn based on the approved distribution charge per customer or (ii) a negative adjustment equal to the amount by which revenue from such distribution sales exceeds the revenue that Pepco is entitled to earn based on the approved distribution charge per customer.

Pepco is a wholly owned subsidiary of PHI. Because PHI is a public utility holding company subject to the Public Utility Holding Company Act of 2005 (PUHCA 2005), the relationship between each of PHI, PHI Service Company (a subsidiary service company of PHI, which provides a variety of support services, including legal, accounting, treasury, tax, purchasing and information technology services to PHI and its operating subsidiaries) and Pepco, as well as certain activities of Pepco, are subject to FERC’s regulatory oversight under PUHCA 2005.

Reliability Enhancement

Since 2010, Pepco has implemented comprehensive reliability enhancement plans in its service territory. These reliability enhancement plans include various initiatives to improve electrical system reliability, such as:

- the identification and upgrading of under-performing feeder lines;
- the addition of new facilities to support load;
- the installation of distribution automation systems on both the overhead and underground network systems;

- the rejuvenation and replacement of underground residential cables;
- selective undergrounding of portions of existing above-ground primary feeder lines, where appropriate to improve reliability;
- improvements to substation supply lines; and
- enhanced vegetation management.

Smart Grid

Pepco is building a smart grid which is designed to meet the challenges of rising energy costs, respond to concerns about the environment, improve reliability, provide timely and accurate customer information and address government energy reduction goals. For a discussion of the smart grid, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Smart Grid."

Mitigation of Regulatory Lag

An important factor in the ability of Pepco to earn its authorized rate of return is the willingness of applicable public service commissions to adequately recognize forward-looking costs in its rate structure in order to address the shortfall in revenues due to the delay in time or "lag" between when costs are incurred and when they are reflected in rates. This delay is commonly known as "regulatory lag." Pepco is currently experiencing significant regulatory lag because its investment in the rate base and its operating expenses are outpacing revenue growth.

In an effort to minimize the effects of regulatory lag, Pepco's District of Columbia and Maryland base rate case filings in 2011 each included a request for approval from the applicable state regulatory commissions of (i) a RIM to recover reliability-related capital expenditures incurred between base rate cases and (ii) the use by the applicable utility of fully forecasted test years in future base rate cases. In June 2012, the MPSC rejected Pepco's request to implement the RIM and did not endorse the use by Pepco of fully forecasted test years in future rate cases. However, the MPSC did permit an adjustment to the rate base of Pepco to reflect the actual cost of reliability plant additions outside the test year. In the District of Columbia, the DCPSC denied Pepco's request for approval of a RIM in 2012, and reserved final judgment on the appropriateness of the use by Pepco of a fully forecasted test year in future rate cases.

Pepco will continue to seek cost recovery from applicable public service commissions to reduce the effects of regulatory lag. There can be no assurance that any attempts by Pepco to mitigate regulatory lag will be approved, or that even if approved, the cost recovery mechanisms will fully mitigate the effects of regulatory lag. Until such time as any cost recovery mechanisms are approved, Pepco plans to file rate cases at least annually in an effort to align more closely the revenue and cash flow levels with other operation and maintenance spending and capital investments. Pepco filed its electric distribution base rate case in March 2013 in the District of Columbia, and expects to file its next electric distribution base rate case in Maryland by the end of 2013. In Maryland, Pepco included a proposed three-year Grid Resiliency Charge rider intended to reduce regulatory lag. In July 2013, the MPSC issued an order that only partially approved the proposed Grid Resiliency Charge. See Note (6), "Regulatory Matters – Rate Proceedings," to the financial statements of Pepco for more information about these base rate cases. On July 26, 2013, Pepco filed a notice of appeal of this MPSC order. Furthermore, Pepco is continuing to review the impact of this order and consider other actions to more closely align its spending in Maryland to the revenue received while maintaining compliance with the MPSC's established standards applicable to Pepco.

MAPP Project

On August 24, 2012, the board of PJM terminated the MAPP project and removed it from PJM's regional transmission expansion plan. PHI had been directed to construct the MAPP project, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region's transmission system. In December 2012, PHI submitted a filing to FERC seeking recovery of $50 million of abandoned MAPP costs over a five-year recovery period. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

In February 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of Pepco, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs. FERC reduced the ROE applicable to the abandoned costs from the previously approved 12.8% incentive ROE to 10.8% by disallowing 200 basis points of ROE adders. FERC also denied recovery of 50% (calculated by Pepco to be $1 million) of the prudently incurred abandoned costs prior to November 1, 2008, the date of FERC's MAPP incentive order. Pepco believes that the February 2013 FERC order is not consistent with prior precedent and is vigorously pursuing its rights to recover all prudently incurred abandoned costs associated with the MAPP project, as well as the full ROE previously approved by FERC. In April 2013, PHI filed a rehearing request on behalf of Pepco of the February 2013 FERC order challenging the reduction of the ROE applicable to the abandoned costs, as well as the denial of 50% of the costs incurred prior to November 1, 2008. On that same date, a group of public advocates from Maryland, Delaware, New Jersey, Virginia, West Virginia and Pennsylvania also filed a rehearing request challenging the 10.8% ROE authorized in FERC's order, arguing that PHI is not entitled to any rate of return on the abandoned costs and that FERC improperly failed to set the ROE for hearing. Pepco is currently engaged in settlement negotiations in this matter; however, Pepco cannot predict when a final FERC decision in this proceeding will be issued.

As of September 30, 2013, Pepco had a regulatory asset related to MAPP abandoned costs of $39 million, representing the original filing amount of approximately $50 million of abandoned costs referred to above less: (i) approximately $1 million of disallowed costs written off in 2013; (ii) $5 million of materials transferred to inventories for use on other projects; and (iii) $5 million of amortization expense recorded in 2013. The regulatory asset balance includes the costs of land, land rights, engineering and design, environmental services, and project management and administration. Pepco intends to reduce further the amount of the regulatory asset by any amounts recovered from the sale or alternative use of the land.

Transmission ROE Challenge

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Electric Municipal Corporation, Inc., filed a joint complaint with FERC against Pepco, DPL and ACE, as well as BGE. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that Pepco provides. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for Pepco is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. Pepco believes the allegations in this complaint are without merit and is vigorously contesting it. On April 3, 2013, Pepco filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable.

Results of Operations

The following results of operations discussion compares the nine months ended September 30, 2013 to the nine months ended September 30, 2012. All amounts in the tables (except sales and customers) are in millions of dollars.

Operating Revenue

	2013	2012	Change
Regulated T&D Electric Revenue	$ 929	$ 884	$ 45
Default Electricity Supply Revenue	598	595	3
Other Electric Revenue	24	24	—
Total Operating Revenue	$1,551	$1,503	$ 48

The table above shows the amount of Operating Revenue earned that is subject to price regulation (Regulated T&D Electric Revenue and Default Electricity Supply Revenue) and that which is not subject to price regulation (Other Electric Revenue).

Regulated T&D Electric Revenue includes revenue from the distribution of electricity, including the distribution of Default Electricity Supply, to Pepco's customers within its service territory at regulated rates. Regulated T&D Electric Revenue also includes transmission service revenue that Pepco receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

The costs related to Default Electricity Supply are included in Purchased Energy. Default Electricity Supply Revenue also includes transmission enhancement credits that Pepco receives as a transmission owner from PJM for approved regional transmission expansion plan costs.

Other Electric Revenue includes work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services include mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Regulated T&D Electric

	2013	2012	Change
Regulated T&D Electric Revenue			
Residential	$ 280	$ 261	$ 19
Commercial and industrial	518	504	14
Transmission and other	131	119	12
Total Regulated T&D Electric Revenue	$ 929	$ 884	$ 45

	2013	2012	Change
Regulated T&D Electric Sales (GWh)			
Residential	6,090	6,072	18
Commercial and industrial	13,576	13,869	(293)
Transmission and other	115	113	2
Total Regulated T&D Electric Sales	19,781	20,054	(273)

	2013	2012	Change
Regulated T&D Electric Customers (in thousands)			
Residential	721	716	5
Commercial and industrial	74	74	—
Transmission and other	—	—	—
Total Regulated T&D Electric Customers	795	790	5

Regulated T&D Electric Revenue increased by $45 million primarily due to:

- An increase of $36 million due to distribution rate increases in the District of Columbia effective October 2012 and in Maryland effective July 2012 and July 2013.
- An increase of $8 million in transmission revenue rates effective June 1, 2012 and June 1, 2013 related to increases in transmission plant investment and operating expenses.
- An increase of $5 million in transmission revenue related to the recovery of MAPP abandoned costs, as approved by FERC (which is offset in Depreciation and Amortization).
- An increase of $4 million in transmission revenue primarily attributable to higher capacity revenue as a result of expanding Maryland demand side management programs (which is substantially offset by a corresponding increase in Depreciation and Amortization).

The aggregate amount of these increases was partially offset by:

- A decrease of $5 million in transmission revenue primarily attributable to a FERC formula rate true-up.
- A decrease of $4 million in distribution revenue due to lower pass-through revenue (which is substantially offset by a corresponding decrease in Other Taxes) primarily the result of a decrease in sales that resulted in a decrease in Montgomery County, Maryland utility taxes that are collected by Pepco on behalf of the jurisdiction.

Default Electricity Supply

	2013	2012	Change
Default Electricity Supply Revenue			
Residential	$ 417	$ 426	$ (9)
Commercial and industrial	169	161	8
Other	12	8	4
Total Default Electricity Supply Revenue	$ 598	$ 595	$ 3

	2013	2012	Change
Default Electricity Supply Sales (GWh)			
Residential	4,621	4,797	(176)
Commercial and industrial	2,067	2,057	10
Other	12	5	7
Total Default Electricity Supply Sales	6,700	6,859	(159)

	2013	2012	Change
Default Electricity Supply Customers (in thousands)			
Residential	558	577	(19)
Commercial and industrial	44	44	—
Other	—	—	—
Total Default Electricity Supply Customers	602	621	(19)

Default Electricity Supply Revenue increased by $3 million primarily due to:

- An increase of $11 million as a result of higher Default Electricity Supply rates.
- An increase of $4 million primarily due to higher revenue from transmission enhancement credits.

The aggregate amount of these increases was partially offset by:

- A decrease of $11 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A decrease of $2 million due to lower sales as a result of milder weather during the 2013 summer months, as compared to 2012.

The following table shows the percentages of Pepco's total distribution sales by jurisdiction that are derived from customers receiving Default Electricity Supply from Pepco. Amounts are for the nine months ended September 30:

	2013	2012
Sales to District of Columbia customers	26%	25%
Sales to Maryland customers	40%	41%

<u>*Operating Expenses*</u>

Purchased Energy

Purchased Energy consists of the cost of electricity purchased by Pepco to fulfill its Default Electricity Supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders. Purchased Energy increased by $4 million to $576 million in 2013 from $572 million in 2012 primarily due to an increase of $18 million due to higher average electricity costs under Default Electricity Supply contracts.

The increase was partially offset by:

- A decrease of $10 million primarily due to customer migration to competitive suppliers.
- A decrease of $2 million due to lower electricity sales primarily as a result of milder weather during the 2013 summer months, as compared to 2012.
- A decrease of $2 million in deferred electricity expense primarily due to higher Default Electricity Supply rates, which resulted in a lower rate of recovery of Default Electricity Supply costs.

Other Operation and Maintenance

Other Operation and Maintenance expense decreased by $9 million to $292 million in 2013 from $301 million in 2012 primarily due to:

- A decrease of $7 million associated with lower maintenance and tree trimming costs.
- A decrease of $5 million in customer service costs.
- A decrease of $5 million in other storm restoration costs.

The aggregate amount of these decreases was partially offset by:

- An increase of $5 million primarily due to 2012 total incremental storm restoration costs for major storm events as described in the following table:

	2013	2012	Change
Regulatory asset established for future recovery of January 2011 winter storm costs	$—	$ (9)	$ 9
Costs associated with derecho storm (June 2012)	—	25	(25)
Regulatory assets established for future recovery of derecho storm costs	—	(21)	21
Total incremental major storm restoration costs	$—	$ (5)	$ 5

  - In January 2011, Pepco incurred incremental storm restoration costs of $10 million associated with a severe winter storm, all of which were expensed in 2011. In July 2012, the MPSC issued an order allowing for the deferral and recovery of $9 million of such costs over a five-year period.
  - In the second and third quarter of 2012, Pepco incurred incremental storm restoration costs of $25 million associated with the June 2012 derecho which resulted in widespread damage to the electric distribution system in each of Pepco's service territories. Pepco deferred $21 million of these costs as a regulatory asset to reflect the probable recovery of these storm restoration costs in Maryland. The MPSC approved the recovery of these costs in Maryland for Pepco in its July 2013 rate order over a five-year period. The remaining costs of $4 million relate to repair work completed in the District of Columbia, which costs are not currently deferrable.
- An increase of $2 million in environmental remediation costs.
- An increase of $1 million associated with the write-off of disallowed MAPP costs.

Depreciation and Amortization

Depreciation and Amortization expense increased by $4 million to $147 million in 2013 from $143 million in 2012 primarily due to:

- An increase of $6 million in amortization of regulatory assets primarily related to recoverable AMI costs, major storm costs and rate case costs.
- An increase of $5 million in amortization of MAPP abandoned costs (which is offset in Regulated T&D Electric Revenue).

The aggregate amount of these increases was partially offset by a decrease of $6 million primarily due to lower depreciation rates, partially offset by plant additions.

Other Taxes

Other Taxes decreased by $5 million to $280 million in 2013 from $285 million in 2012. The decrease was primarily due to decreases in the Montgomery County, Maryland utility taxes that are collected and passed through by Pepco (substantially offset by a corresponding decrease in Regulated T&D Electric Revenue).

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $5 million to a net expense of $68 million in 2013 from a net expense of $63 million in 2012. The increase was primarily due to an increase of $6 million in interest expense primarily associated with higher long-term debt.

Income Tax Expense

Pepco's income tax expense increased by $24 million to $62 million in 2013 from $38 million in 2012. Pepco's effective tax rates for the nine months ended September 30, 2013 and 2012 were 33.0% and 27.3%, respectively. The increase in the effective tax rate primarily resulted from changes in estimates and interest related to uncertain and effectively settled tax positions.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which Pepco is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. As a result of the court's ruling in this case, PHI determined in the first quarter of 2013 that it could no longer support its current assessment with respect to the likely outcome of tax positions associated with its cross-border energy lease investments held by its wholly-owned subsidiary Potomac Capital Investment Corporation, and PHI recorded a charge of $377 million (after-tax) in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $54 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in Pepco recording a $5 million interest benefit in the first quarter of 2013.

In 2012, Pepco recorded tax benefits of $11 million for changes in estimates and interest related to uncertain and effectively settled tax positions primarily due to the effective settlement with the IRS with respect to the methodology used historically to calculate deductible mixed service costs and the expiration of the statute of limitations associated with an uncertain tax position.

Capital Requirements

Capital Expenditures

Pepco's capital expenditures for the nine months ended September 30, 2013 were $403 million. These expenditures were primarily related to capital costs associated with new customer services, distribution reliability and transmission. The expenditures also include an allocation by PHI of hardware and software expenditures that primarily benefit Power Delivery and are allocated to Pepco when the assets are placed in service.

Pepco's projected capital expenditures for the five-year period from 2014 through 2018 are summarized below. Pepco expects to fund these expenditures through internally generated cash and external financing.

	For the Year Ended December 31,					
	2014	2015	2016	2017	2018	Total
			(millions of dollars)			
Pepco						
Distribution	$505	$480	$481	$442	$465	$2,373
Transmission	113	74	43	74	91	395
Other	91	54	36	29	23	233
Total Pepco	$709	$608	$560	$545	$579	$3,001

Pepco has several construction projects within its service territory where performance has been subcontracted to Pepco Energy Services. Pepco guarantees the obligations of Pepco Energy Services under surety bonds obtained by Pepco Energy Services for these projects. These guarantees totaled $16 million at September 30, 2013.

DOE Capital Reimbursement Awards

During 2009, the DOE announced a $168 million award to PHI under the American Recovery and Reinvestment Act of 2009 for the implementation of an AMI system, direct load control, distribution automation, and communications infrastructure. Pepco was awarded $149 million, with $105 million to be used in the Maryland service territory and $44 million to be used in the District of Columbia service territory.

During 2010, Pepco and the DOE signed agreements formalizing Pepco's $149 million share of the $168 million award. Of the $149 million, $118 million is being used for the smart grid and other capital expenditures of Pepco. The remaining $31 million is being used to offset incremental expenses associated with direct load control and other programs. For the nine months ended September 30, 2013, Pepco received award payments of $24 million. Cumulative award payments received by Pepco as of September 30, 2013 were $139 million.

The IRS has announced that, to the extent these grants are expended on capital items, they will not be considered taxable income.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Delmarva Power & Light Company

DPL meets the conditions set forth in General Instruction H(1)(a) and (b) to the Form 10-Q, and accordingly information otherwise required under this Item has been omitted in accordance with General Instruction H(2) to Form 10-Q.

General Overview

DPL is engaged in the transmission and distribution of electricity in Delaware and portions of Maryland. DPL also provides Default Electricity Supply. DPL's electricity distribution service territory covers approximately 5,000 square miles and has a population of approximately 1.4 million. As of September 30, 2013, approximately 66% of delivered electricity sales were to Delaware customers and approximately 34% were to Maryland customers. In northern Delaware, DPL also supplies and distributes natural gas to retail customers and provides transportation-only services to retail customers who purchase natural gas from other suppliers. DPL's natural gas distribution service territory covers approximately 275 square miles and has a population of approximately 500,000.

DPL's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of DPL in Maryland, revenues are not affected by unseasonably warmer or colder weather because a BSA for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. A comparable revenue decoupling mechanism for DPL electricity and natural gas customers in Delaware is under consideration by the DPSC. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

In accounting for the BSA in Maryland, a Revenue Decoupling Adjustment is recorded representing either (i) a positive adjustment equal to the amount by which revenue from Maryland retail distribution sales falls short of the revenue that DPL is entitled to earn based on the approved distribution charge per customer or (ii) a negative adjustment equal to the amount by which revenue from such distribution sales exceeds the revenue that DPL is entitled to earn based on the approved distribution charge per customer.

DPL is a wholly owned subsidiary of Conectiv, LLC (Conectiv) which is wholly owned by PHI. Because each of PHI and Conectiv is a public utility holding company subject to PUHCA 2005, the relationship between each of PHI, Conectiv, PHI Service Company and DPL, as well as certain activities of DPL, are subject to FERC's regulatory oversight under PUHCA 2005.

Smart Grid

DPL is building a smart grid which is designed to meet the challenges of rising energy costs, respond to concerns about the environment, improve reliability, provide timely and accurate customer information and address government energy reduction goals. For a discussion of the smart grid, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Smart Grid."

Mitigation of Regulatory Lag

An important factor in the ability of DPL to earn its authorized rate of return is the willingness of applicable public service commissions to adequately recognize forward-looking costs in its rate structure in order to address the shortfall in revenues due to the delay in time or “lag” between when costs are incurred and when they are reflected in rates. This delay is commonly known as “regulatory lag.” DPL is currently experiencing significant regulatory lag because its investment in the rate base and its operating expenses are outpacing revenue growth.

In an effort to minimize the effects of regulatory lag, DPL’s Delaware and Maryland base rate case filings in 2011 each included a request for approval from the applicable state regulatory commissions of (i) a RIM to recover reliability-related capital expenditures incurred between base rate cases and (ii) the use by the applicable utility of fully forecasted test years in future base rate cases. In June 2012, the MPSC rejected DPL’s requests to implement the RIM and did not endorse the use by DPL of fully forecasted test years in future rate cases. However, the MPSC did permit an adjustment to the rate base of DPL to reflect the actual cost of reliability plant additions outside the test year. In Delaware, a settlement agreement approved by the DPSC in DPL’s electric distribution base rate case did not include approval of a RIM or the use of fully forecasted test years in future DPL rate cases, but it did provide that the parties will meet and discuss alternate regulatory methodologies for the mitigation of regulatory lag.

DPL will continue to seek cost recovery from applicable public service commissions to reduce the effects of regulatory lag. There can be no assurance that any attempts by DPL to mitigate regulatory lag will be approved, or that even if approved, the cost recovery mechanisms will fully mitigate the effects of regulatory lag. Until such time as any cost recovery mechanisms are approved, DPL plans to file rate cases at least annually in an effort to align more closely the revenue and cash flow levels with other operation and maintenance spending and capital investments. DPL filed electric distribution base rate cases in both Delaware and Maryland in March 2013, and filed a natural gas distribution case in December 2012. In DPL’s electric distribution base rate case filed in Maryland, DPL included a proposed three-year Grid Resiliency Charge rider intended to reduce regulatory lag. In August 2013, the MPSC issued an order in the DPL Maryland electric base rate case that only partially approved the proposed Grid Resiliency charge. See Note (7), “Regulatory Matters – Rate Proceedings,” to the financial statements of DPL for more information about these base rate cases.

In Delaware, DPL filed a multi-year rate plan on October 2, 2013, referred to as the Forward Looking Rate Plan (FLRP). As proposed, the FLRP would establish electric distribution base rates for a period of four years into the future. See Note (7), “Regulatory Matters – Rate Proceedings – Delaware – Forward Looking Rate Plan,” to the financial statements of DPL for more information about this filing.

MAPP Project

On August 24, 2012, the board of PJM terminated the MAPP project and removed it from PJM’s regional transmission expansion plan. PHI had been directed to construct the MAPP project, a 152-mile high-voltage interstate transmission line, to address the reliability needs of the region’s transmission system. In December 2012, PHI submitted a filing to FERC seeking recovery of $38 million of abandoned MAPP costs over a five-year recovery period. The FERC filing addressed, among other things, the prudence of the recoverable costs incurred, the proposed period over which the abandoned costs are to be amortized and the rate of return on these costs during the recovery period.

In February 2013, FERC issued an order concluding that the MAPP project was cancelled for reasons beyond the control of DPL, finding that the prudently incurred costs associated with the abandonment of the MAPP project are eligible to be recovered, and setting for hearing and settlement procedures the prudence of the abandoned costs and the amortization period for those costs. FERC reduced the ROE applicable to the abandoned costs from the previously approved 12.8% incentive ROE to 10.8% by disallowing 200 basis points of ROE adders. FERC also denied recovery of 50% (calculated by DPL to be $1 million) of the prudently incurred abandoned costs prior to November 1, 2008, the date of FERC’s

MAPP incentive order. DPL believes that the February 2013 FERC order is not consistent with prior precedent and is vigorously pursuing its rights to recover all prudently incurred abandoned costs associated with the MAPP project, as well as the full ROE previously approved by FERC. In April 2013, PHI filed a rehearing request on behalf of DPL of the February 2013 FERC order challenging the reduction of the ROE applicable to the abandoned costs, as well as the denial of 50% of the costs incurred prior to November 1, 2008. On that same date, a group of public advocates from Maryland, Delaware, New Jersey, Virginia, West Virginia and Pennsylvania also filed a rehearing request challenging the 10.8% ROE authorized in FERC's order, arguing that DPL is not entitled to any rate of return on the abandoned costs and that FERC improperly failed to set the ROE for hearing. DPL is currently engaged in settlement negotiations in this matter; however, DPL cannot predict when a final FERC decision in this proceeding will be issued.

As of September 30, 2013, DPL had a regulatory asset related to the MAPP abandoned costs of $32 million, representing the original filing amount of approximately $38 million of abandoned costs referred to above less: (i) approximately $1 million of disallowed costs written off in 2013; and (ii) $5 million of amortization expense recorded in 2013. The regulatory asset balance includes the costs of land, land rights, engineering and design, environmental services, and project management and administration. DPL intends to reduce further the amount of the regulatory asset by any amounts recovered from the sale or alternative use of the land.

Transmission ROE Challenge

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Electric Municipal Corporation, Inc., filed a joint complaint with FERC against DPL, Pepco and ACE, as well as BGE. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that DPL provides. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for DPL is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. DPL believes the allegations in this complaint are without merit and is vigorously contesting it. On April 3, 2013, DPL filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable.

Results of Operations

The following results of operations discussion compares the nine months ended September 30, 2013 to the nine months ended September 30, 2012. All amounts in the tables (except sales and customers) are in millions of dollars.

Electric Operating Revenue

	2013	2012	Change
Regulated T&D Electric Revenue	$372	$340	$ 32
Default Electricity Supply Revenue	413	458	(45)
Other Electric Revenue	10	10	—
Total Electric Operating Revenue	$795	$808	$ (13)

The table above shows the amount of Electric Operating Revenue earned that is subject to price regulation (Regulated T&D Electric Revenue and Default Electricity Supply Revenue) and that which is not subject to price regulation (Other Electric Revenue).

Regulated T&D Electric Revenue includes revenue from the distribution of electricity, including the distribution of Default Electricity Supply, to DPL's customers within its service territories at regulated rates. Regulated T&D Electric Revenue also includes transmission service revenue that DPL receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

The costs related to Default Electricity Supply are included in Purchased Energy. Default Electricity Supply Revenue also includes transmission enhancement credits that DPL receives as a transmission owner from PJM for approved regional transmission expansion plan costs.

Other Electric Revenue includes work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services include mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Regulated T&D Electric

	2013	2012	Change
Regulated T&D Electric Revenue			
Residential	$ 174	$ 161	$ 13
Commercial and industrial	105	97	8
Transmission and other	93	82	11
Total Regulated T&D Electric Revenue	$ 372	$ 340	$ 32

	2013	2012	Change
Regulated T&D Electric Sales (GWh)			
Residential	3,929	3,931	(2)
Commercial and industrial	5,542	5,726	(184)
Transmission and other	35	37	(2)
Total Regulated T&D Electric Sales	9,506	9,694	(188)

	2013	2012	Change
Regulated T&D Electric Customers (in thousands)			
Residential	444	442	2
Commercial and industrial	60	59	1
Transmission and other	1	1	—
Total Regulated T&D Electric Customers	505	502	3

Regulated T&D Electric Revenue increased by $32 million primarily due to:

- An increase of $20 million due to distribution rate increases in Maryland effective July 2012 and September 2013, and in Delaware effective July 2012.
- An increase of $7 million primarily due to a Renewable Portfolio Surcharge in Delaware effective June 2012 (which is substantially offset by a corresponding increase in Purchased Energy and Depreciation and Amortization).
- An increase of $6 million in transmission revenue related to the resale by DPL of renewable energy in Delaware (which is substantially offset by a corresponding increase in Purchased Energy and Depreciation and Amortization).
- An increase of $5 million in transmission revenue related to the recovery of MAPP abandoned costs, as approved by FERC.
- An increase of $2 million in transmission revenue rates effective June 1, 2013 related to increases in transmission plant investment and operating expenses.

The aggregate amount of these increases was partially offset by:

- A decrease of $7 million due to lower non-weather related average customer usage.
- A decrease of $3 million in transmission revenue primarily attributable to a FERC formula rate true-up.

Default Electricity Supply

	2013	2012	Change
Default Electricity Supply Revenue			
Residential	$ 318	$ 354	$ (36)
Commercial and industrial	87	96	(9)
Other	8	8	—
Total Default Electricity Supply Revenue	$ 413	$ 458	$ (45)

	2013	2012	Change
Default Electricity Supply Sales (GWh)			
Residential	3,452	3,583	(131)
Commercial and industrial	1,029	1,311	(282)
Other	20	22	(2)
Total Default Electricity Supply Sales	4,501	4,916	(415)

	2013	2012	Change
Default Electricity Supply Customers (in thousands)			
Residential	394	405	(11)
Commercial and industrial	38	40	(2)
Other	—	—	—
Total Default Electricity Supply Customers	432	445	(13)

Default Supply Revenue decreased by $45 million primarily due to:

- A decrease of $22 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A decrease of $16 million as a result of lower Default Electricity Supply rates.
- A decrease of $12 million due to lower non-weather related average customer usage.

The aggregate amount of these decreases was partially offset by an increase of $5 million due to higher sales primarily as a result of colder weather during the 2013 winter months, as compared to 2012.

The following table shows the percentages of DPL's total distribution sales by jurisdiction that are derived from customers receiving Default Electricity Supply from DPL. Amounts are for the nine months ended September 30:

	2013	2012
Sales to Delaware customers	45%	49%
Sales to Maryland customers	52%	54%

Natural Gas Operating Revenue

	2013	2012	Change
Regulated Gas Revenue	$114	$102	$ 12
Other Gas Revenue	23	22	1
Total Natural Gas Operating Revenue	$137	$124	$ 13

The table above shows the amounts of Natural Gas Operating Revenue from sources that are subject to price regulation (Regulated Gas Revenue) and those that generally are not subject to price regulation (Other Gas Revenue). Regulated Gas Revenue includes the revenue DPL receives from on-system natural gas delivered sales and the transportation of natural gas for customers within its service territory at regulated rates. Other Gas Revenue includes off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers. Off-system sales are made possible when low demand for natural gas by regulated customers creates excess pipeline capacity.

Regulated Gas

	2013	2012	Change
Regulated Gas Revenue			
Residential	$ 71	$ 63	$ 8
Commercial and industrial	35	32	3
Transportation and other	8	7	1
Total Regulated Gas Revenue	$ 114	$ 102	$ 12

	2013	2012	Change
Regulated Gas Sales (million cubic feet)			
Residential	5,365	4,052	1,313
Commercial and industrial	3,232	2,310	922
Transportation and other	5,141	4,877	264
Total Regulated Gas Sales	13,738	11,239	2,499

	2013	2012	Change
Regulated Gas Customers (in thousands)			
Residential	116	115	1
Commercial and industrial	9	9	—
Transportation and other	—	—	—
Total Regulated Gas Customers	125	124	1

Regulated Gas Revenue increased by $12 million primarily due to:

- An increase of $20 million due to higher sales primarily as a result of colder weather during the winter months of 2013 as compared to 2012.
- An increase of $4 million due to higher non-weather related average commercial customer usage.
- An increase of $4 million due to a revenue adjustment recorded in June 2012 for a reduction in the estimate of gas sold but not yet billed to customers (which is partially offset by an increase in Purchased Energy).
- An increase of $1 million due to a distribution rate increase effective July 2013.

The aggregate amount of these increases was partially offset by a decrease of $18 million due to a GCR decrease effective November 2012.

<u>*Operating Expenses*</u>

Purchased Energy

Purchased Energy consists of the cost of electricity purchased by DPL to fulfill its Default Electricity Supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders. Purchased Energy decreased by $21 million to $422 million in 2013 from $443 million in 2012 primarily due to:

- A decrease of $37 million primarily due to customer migration to competitive suppliers.
- A decrease of $25 million in deferred electricity expense primarily due to higher Default Electricity Supply rates, which resulted in a lower rate of recovery of Default Electricity Supply costs.

The aggregate amount of these decreases was partially offset by:

- An increase of $21 million due to higher average electricity costs under Default Electricity Supply contracts.
- An increase of $13 million in deferred electricity expense primarily due to a Renewable Portfolio Surcharge in Delaware effective June 2012 (which is substantially offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $5 million in Renewable Energy Credits in Delaware (which is offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $4 million due to higher electricity sales primarily as a result of colder weather during the 2013 winter months, as compared to 2012.

Gas Purchased

Gas Purchased consists of the cost of gas purchased by DPL to fulfill its obligation to regulated gas customers and, as such, is recoverable from customers in accordance with the terms of public service commission orders. It also includes the cost of gas purchased for off-system sales. Total Gas Purchased increased by $3 million to $80 million in 2013 from $77 million in 2012 primarily due to:

- An increase of $9 million in the cost of gas purchases for on-system sales as a result of higher average gas prices.
- An increase of $4 million in the cost of gas purchases for on-system sales as a result of an adjustment recorded in June 2012 for a reduction in the estimate of gas sold but not yet billed to customers (which is offset by an increase in Regulated Gas Revenue).

The aggregate amount of these increases was partially offset by:

- A decrease of $10 million from the settlement of financial hedges entered into as part of DPL’s hedge program for the purchase of regulated natural gas.

Other Operation and Maintenance

Other Operation and Maintenance expense decreased by $1 million to $191 million in 2013 from $192 million in 2012 primarily due to:

- A decrease of $4 million associated with lower maintenance costs.
- A decrease of $3 million in customer service costs.
- A decrease of $1 million primarily due to 2012 total incremental storm restoration costs for major storm events as described in the following table:

	2013	2012	Change
Costs associated with derecho storm (June 2012)	$—	$ 2	$ (2)
Regulatory assets established for future recovery of derecho storm costs	—	(1)	1
Total incremental major storm restoration costs	$—	$ 1	$ (1)

- In the second and third quarter of 2012, DPL incurred incremental storm restoration costs of $2 million associated with the June 2012 derecho which resulted in widespread damage to the electric distribution system in each of DPL's service territories. DPL deferred $1 million of these costs as a regulatory asset to reflect the probable recovery of these storm restoration costs in Maryland. The MPSC approved the recovery of these costs in Maryland for DPL in its August 2013 electric distribution base rate order over a five-year period. The remaining costs of $1 million primarily relate to repair work completed in Delaware, which costs are not currently deferrable.

The aggregate amount of these decreases was partially offset by:

- An increase of $6 million resulting from 2012 deferred cost adjustments associated with DPL Default Electricity Supply. The deferred cost adjustments were primarily due to the under-recognition of allowed returns on net uncollectible expense and regulatory taxes in 2012.
- An increase of $2 million associated with the write-offs of disallowed MAPP and associated transmission projects costs.

Depreciation and Amortization

Depreciation and Amortization expense increased by $1 million to $79 million in 2013 from $78 million in 2012 primarily due to:

- An increase of $5 million in amortization of MAPP abandoned costs (which is offset by a corresponding increase in Regulated T&D Electric Revenue).
- An increase of $2 million in amortization of regulatory costs assets primarily related to recoverable AMI costs, major storm costs and rate case costs.

The aggregate amount of these increases was partially offset by a decrease of $6 million in the Delaware Renewable Energy Portfolio Standards deferral (which is substantially offset by a corresponding decrease in Regulated T&D Electric Revenue).

Other Taxes

Other Taxes increased by $3 million to $29 million in 2013 from $26 million in 2012. The increase was primarily due to higher property taxes.

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $5 million to a net expense of $31 million in 2013 from a net expense of $26 million in 2012. The increase was primarily due to an increase of $4 million in long-term debt interest expense due to the issuance of $250 million of First Mortgage Bonds in June 2012 .

Income Tax Expense

DPL's income tax expense increased by $5 million to $39 million in 2013 from $34 million in 2012. DPL's effective tax rates for the nine months ended September 30, 2013 and 2012 were 39.0% and 37.8%, respectively. The increase in the effective tax rate primarily resulted from adjustments to prior year taxes recorded during the nine months ended September 30, 2012.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which DPL is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. As a result of the court's ruling in this case, PHI determined in the first quarter of 2013 that it could no longer support its current assessment with respect to the likely outcome of tax positions associated with its cross-border energy lease investments held by its wholly-owned subsidiary Potomac Capital Investment Corporation, and PHI recorded a charge of $377 million (after-tax) in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $54 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in DPL recording a $1 million interest benefit in the first quarter of 2013.

Capital Requirements

Capital Expenditures

DPL's capital expenditures for the nine months ended September 30, 2013 were $249 million. These expenditures were primarily related to capital costs associated with new customer services, distribution reliability and transmission. The expenditures also include an allocation by PHI of hardware and software expenditures that primarily benefit Power Delivery and are allocated to DPL when the assets are placed in service.

DPL's projected capital expenditures for the five-year period from 2014 through 2018 are summarized below. DPL expects to fund these expenditures through internally generated cash and external financing.

	For the Year Ended December 31,					
	2014	2015	2016	2017	2018	Total
			(millions of dollars)			
DPL						
Distribution	$162	$149	$153	$159	$155	$ 778
Distribution – Smart Grid (AMI)	2	—	—	—	—	2
Transmission	96	88	119	96	138	537
Gas Delivery	29	28	28	28	29	142
Other	51	32	24	28	20	155
Total DPL	$340	$297	$324	$311	$342	$1,614

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Atlantic City Electric Company

ACE meets the conditions set forth in General Instruction H(1)(a) and (b) to the Form 10-Q, and accordingly information otherwise required under this Item has been omitted in accordance with General Instruction H(2) to Form 10-Q.

General Overview

ACE is engaged in the transmission and distribution of electricity in southern New Jersey. ACE also provides Default Electricity Supply. Default Electricity Supply is known as BGS in New Jersey. ACE's service territory covers approximately 2,700 square miles and has a population of approximately 1.1 million.

ACE is a wholly owned subsidiary of Conectiv, which is wholly owned by PHI. Because each of PHI and Conectiv is a public utility holding company subject to PUHCA 2005, the relationship between each of PHI, Conectiv, PHI Service Company and ACE, as well as certain activities of ACE, are subject to FERC's regulatory oversight under PUHCA 2005.

Smart Grid

ACE is building a smart grid which is designed to meet the challenges of rising energy costs, respond to concerns about the environment, improve reliability, provide timely and accurate customer information and address government energy reduction goals. The installation of smart meters currently has been deferred by the NJBPU. For a discussion of the smart grid, see PHI's "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview – Power Delivery Initiatives and Activities – Smart Grid."

Mitigation of Regulatory Lag

An important factor in the ability of ACE to earn its authorized rate of return is the willingness of the NJBPU to adequately recognize forward-looking costs in its rate structure in order to address the shortfall in revenues due to regulatory lag. ACE is currently experiencing significant regulatory lag because its investment in the rate base and its operating expenses are outpacing revenue growth. The NJBPU has approved certain cost recovery mechanisms in connection with ACE's Infrastructure Investment Program, which ACE had proposed in 2011 to extend and expand; however, in connection with the settlement in October 2012 of its electric distribution base rate case, ACE withdrew this proposal without prejudice. There can be no assurance that any future attempts by ACE to mitigate regulatory lag will be approved, or that even if approved, any proposed cost recovery mechanisms will fully mitigate the effects of regulatory lag. Until such time as any cost recovery mechanisms are approved, ACE plans to file rate cases at least annually in an effort to align more closely its revenue and cash flow levels with other operation and maintenance spending and capital investments. ACE filed an electric distribution base rate case on December 11, 2012. See Note (6), "Regulatory Matters – Rate Proceedings," to the consolidated financial statements of ACE for more information about this base rate case.

Transmission ROE Challenge

On February 27, 2013, the public service commissions and public advocates of the District of Columbia, Maryland, Delaware and New Jersey, as well as the Delaware Electric Municipal Corporation, Inc., filed a joint complaint with FERC against Pepco, DPL and ACE, as well as BGE. The complainants challenged the base ROE and the application of the formula rate process, each associated with the transmission service that PHI's utilities provide. The complainants support an ROE within a zone of reasonableness of 6.78% and 10.33%, and have argued for a base ROE of 8.7%. The base ROE currently authorized by FERC for ACE is (i) 11.3% for facilities placed into service after January 1, 2006, and (ii) 10.8% for facilities placed into service prior to 2006. As currently authorized, the 10.8% base ROE for facilities placed into service prior to 2006 is eligible for a 50-basis-point incentive adder for being a member of a regional transmission organization. ACE believes the allegations in this complaint are without merit and is vigorously contesting it. On April 3, 2013, ACE filed its answer to this complaint, requesting that FERC dismiss the complaint against it on the grounds that it failed to meet the required burden to demonstrate that the existing rates and protocols are unjust and unreasonable.

Results of Operations

The following results of operations discussion compares the nine months ended September 30, 2013 to the nine months ended September 30, 2012. All amounts in the tables (except sales and customers) are in millions of dollars.

Operating Revenue

	2013	2012	Change
Regulated T&D Electric Revenue	$324	$299	$ 25
Default Electricity Supply Revenue	609	628	(19)
Other Electric Revenue	11	12	(1)
Total Operating Revenue	$944	$939	$ 5

The table above shows the amount of Operating Revenue earned that is subject to price regulation (Regulated T&D Electric Revenue and Default Electricity Supply Revenue) and that which is not subject to price regulation (Other Electric Revenue).

Regulated T&D Electric Revenue includes revenue from the distribution of electricity, including the distribution of Default Electricity Supply, to ACE's customers within its service territory at regulated rates. Regulated T&D Electric Revenue also includes transmission service revenue that ACE receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

The costs related to Default Electricity Supply are included in Purchased Energy. Default Electricity Supply Revenue also includes revenue from Transition Bond Charges that ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds, and revenue in the form of transmission enhancement credits.

Other Electric Revenue includes work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services include mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Regulated T&D Electric

	2013	2012	Change
Regulated T&D Electric Revenue			
Residential	$147	$133	$ 14
Commercial and industrial	110	98	12
Transmission and other	67	68	(1)
Total Regulated T&D Electric Revenue	$324	$299	$ 25

	2013	2012	Change
Regulated T&D Electric Sales (GWh)			
Residential	3,323	3,471	(148)
Commercial and industrial	3,769	3,898	(129)
Transmission and other	33	33	—
Total Regulated T&D Electric Sales	7,125	7,402	(277)

	2013	2012	Change
Regulated T&D Electric Customers (in thousands)			
Residential	478	481	(3)
Commercial and industrial	65	65	—
Transmission and other	1	1	—
Total Regulated T&D Electric Customers	544	547	(3)

Regulated T&D Electric Revenue increased by $25 million primarily due to:

- An increase of $30 million due to distribution rate increases effective November 2012 and July 2013, and a customer charge rate increase effective November 2012.
- An increase of $6 million due to a rate increase in the New Jersey Societal Benefit Charge effective July 2012 (which is offset in Deferred Electric Service Costs).

The aggregate amount of these increases was partially offset by:

- A decrease of $6 million due to lower non-weather related average residential and commercial customer usage.
- A decrease of $3 million due to lower sales primarily as a result of milder weather during the 2013 summer months, as compared to 2012.
- A decrease of $2 million in transmission revenue primarily attributable to a peak-load rate decrease effective January 2013.

Default Electricity Supply

	2013	2012	Change
Default Electricity Supply Revenue			
Residential	$352	$391	$ (39)
Commercial and industrial	162	168	(6)
Other	95	69	26
Total Default Electricity Supply Revenue	$609	$628	$ (19)

Other Default Electricity Supply Revenue consists primarily of (i) revenue from the resale in the PJM RTO market of energy and capacity purchased under contracts with unaffiliated NUGs and (ii) revenue from transmission enhancement credits.

	2013	2012	Change
Default Electricity Supply Sales (GWh)			
Residential	2,623	2,876	(253)
Commercial and industrial	813	974	(161)
Other	10	14	(4)
Total Default Electricity Supply Sales	3,446	3,864	(418)

	2013	2012	Change
Default Electricity Supply Customers (in thousands)			
Residential	387	400	(13)
Commercial and industrial	43	46	(3)
Other	—	—	—
Total Default Electricity Supply Customers	430	446	(16)

Default Electricity Supply Revenue decreased by $19 million primarily due to:

- A decrease of $36 million due to lower sales, primarily as a result of customer migration to competitive suppliers.
- A decrease of $13 million due to lower non-weather related average residential and commercial customer usage.
- A decrease of $7 million due to lower sales, primarily as a result of milder weather during the 2013 summer months, as compared to 2012.

The aggregate amount of these decreases was partially offset by:

- An increase of $27 million in wholesale energy and capacity resale revenues primarily due to higher market prices for the resale of electricity and capacity purchased from NUGs.
- An increase of $10 million as a result of higher Default Electricity Supply rates, primarily due to a Nonutility Generation Charge rate increase that became effective in July 2012.

For the nine months ended September 30, 2013 and 2012, the percentages of ACE's total distribution sales that are derived from customers receiving Default Electricity Supply are 48% and 52%, respectively.

Operating Expenses

Purchased Energy

Purchased Energy consists of the cost of electricity purchased by ACE to fulfill its Default Electricity Supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders. Purchased Energy decreased by $46 million to $509 million in 2013 from $555 million in 2012 primarily due to:

- A decrease of $34 million primarily due to customer migration to competitive suppliers.
- A decrease of $8 million due to lower average electricity costs under Default Electricity Supply contracts.
- A decrease of $4 million due to lower electricity sales, primarily as a result of milder weather during the 2013 summer months, as compared to 2012.

Other Operation and Maintenance

Other Operation and Maintenance expense decreased by $1 million to $177 million in 2013 from $178 million in 2012 primarily due to a $1 million decrease in bad debt expenses that is deferred and recoverable.

Other Operation and Maintenance expense also includes the effects of 2012 total incremental storm restoration costs for major storm events as described in the following table:

	2013	2012	Change
Costs associated with derecho storm (June 2012)	$—	$ 13	$ (13)
Regulatory assets established for future recovery of derecho storm costs	—	(13)	13
Total incremental major storm restoration costs	$—	$—	$ —

- In the second and third quarters of 2012, ACE incurred incremental storm restoration costs of $13 million associated with the June 2012 derecho which resulted in widespread damage to the electric distribution system. ACE deferred $13 million of these costs as a regulatory asset to reflect the probable recovery of these storm restoration costs in New Jersey. ACE's stipulation of settlement approved by NJBPU in June 2013 provides for recovery of these costs in New Jersey over a three-year period.

Depreciation and Amortization

Depreciation and Amortization expense increased by $9 million to $101 million in 2013 from $92 million in 2012 primarily due to:

- An increase of $4 million in amortization of storm costs.
- An increase of $2 million due to utility plant additions.
- An increase of $2 million in amortization of stranded costs primarily as a result of higher revenue due to rate increases effective October 2012 for the ACE Market Transition charge tax (partially offset in Default Electric Supply Revenue).

Other Taxes

Other Taxes decreased by $3 million to $11 million in 2013 from $14 million in 2012. The decrease was primarily due to decreased Transitional Energy Facility Assessment taxes due to a rate decrease effective January 2013 (partially offset by a corresponding decrease in Regulated T&D Electric Revenue).

Deferred Electric Service Costs

Deferred Electric Service Costs represent (i) the over or under recovery of electricity costs incurred by ACE to fulfill its Default Electricity Supply obligation and (ii) the over or under recovery of New Jersey Societal Benefit Program costs incurred by ACE. The cost of electricity purchased is reported under Purchased Energy and the corresponding revenue is reported under Default Electricity Supply Revenue. The cost of New Jersey Societal Benefit Programs is reported under Other Operation and Maintenance expense and the corresponding revenue is reported under Regulated T&D Electric Revenue.

Deferred Electric Service Costs increased by $45 million to an expense of $39 million in 2013 as compared to an expense reduction of $6 million in 2012, primarily due to an increase in deferred electricity expense as a result of higher Default Electricity Supply and New Jersey Societal Benefit Programs revenue rates and lower electricity supply costs.

Other Income (Expenses)

Other Expenses (which are net of Other Income) increased by $3 million to a net expense of $52 million in 2013 from a net expense of $49 million in 2012 primarily due to lower income related to AFUDC that is applied to capital projects.

Income Tax Expense

ACE's income tax expense decreased by $7 million to $14 million in 2013 from $21 million in 2012. ACE's consolidated effective tax rates for the nine months ended September 30, 2013 and 2012 were 25.5% and 36.8%, respectively. The change in the effective tax rate primarily resulted from changes in estimates and interest related to uncertain and effectively settled tax positions. In the first quarter of 2013, ACE recorded an interest benefit of $6 million as discussed further below. In the first quarter of 2012, ACE recorded an interest benefit as a result of the effective settlement with the IRS with respect to the methodology used historically to calculate deductible mixed service costs.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which ACE is not a party) that disallowed tax benefits associated with Consolidated Edison's cross-border lease transaction. As a result of the court's ruling in this case, PHI determined in the first quarter of 2013 that it could no longer support its current assessment with respect to the likely outcome of tax positions associated with its cross-border energy lease investments held by its wholly-owned subsidiary Potomac Capital Investment Corporation, and PHI recorded a charge of $377 million (after-tax) in the first quarter of 2013. Included in the $377 million charge was an after-tax interest charge of $54 million and this amount was allocated to each member of PHI's consolidated group as if each member was a separate taxpayer, resulting in ACE recording a $6 million interest benefit in the first quarter of 2013.

Capital Requirements

Capital Expenditures

ACE's capital expenditures for the nine months ended September 30, 2013 were $204 million. These expenditures were primarily related to capital costs associated with new customer services, distribution reliability and transmission. The expenditures also include an allocation by PHI of hardware and software expenditures that primarily benefit Power Delivery and are allocated to ACE when the assets are placed in service.

ACE's projected capital expenditures for the five-year period from 2014 through 2018 are summarized below. ACE expects to fund these expenditures through internally generated cash and external financing.

	For the Year Ended December 31,					
	2014	2015	2016	2017	2018	Total
			(millions of dollars)			
ACE						
Distribution	$107	$ 78	$137	$128	$124	$ 574
Distribution – Smart Grid (AMI)	—	—	—	—	8	8
Transmission	109	128	98	85	56	476
Other	25	16	39	39	22	141
Total ACE	$241	$222	$274	$252	$210	$1,199

DOE Capital Reimbursement Awards

During 2009, the DOE announced a $168 million award to PHI under the American Recovery and Reinvestment Act of 2009 for the implementation of an AMI system, direct load control, distribution automation, and communications infrastructure, of which $19 million was for ACE's service territory.

During 2010, ACE and the DOE signed agreements formalizing ACE's $19 million share of the $168 million award. Of the $19 million, $12 million is being used for the smart grid and other capital expenditures of ACE. The remaining $7 million is being used to offset incremental expenses associated with direct load control and other programs. For the nine months ended September 30, 2013, ACE received award payments of $3 million. Cumulative award payments received by ACE as of September 30, 2013 were $16 million.

The IRS has announced that, to the extent these grants are expended on capital items, they will not be considered taxable income.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Risk management policies for PHI and its subsidiaries are determined by PHI's Corporate Risk Management Committee (CRMC), the members of which are PHI's Chief Risk Officer, Chief Operating Officer, Chief Financial Officer, General Counsel, Chief Information Officer and other senior executives. The CRMC monitors interest rate fluctuation, commodity price fluctuation, credit risk exposure, and sets risk management policies that establish limits on unhedged risk and determine risk reporting requirements. For information about PHI's derivative activities, other than the information otherwise disclosed herein, refer to Note (2), "Significant Accounting Policies – Accounting For Derivatives," Note (14), "Derivative Instruments and Hedging Activities," and Note (19), "Discontinued Operations," of the consolidated financial statements of PHI included in its 2012 Form 10-K, Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" in PHI's 2012 Form 10-K, and Note (12), "Derivative Instruments and Hedging Activities," and Note (16), "Discontinued Operations," of the consolidated financial statements of PHI included herein.

For information regarding "Interest Rate Risk," please refer to Part II, Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," in Pepco Holdings' 2012 Form 10-K.

INFORMATION FOR THIS ITEM IS NOT REQUIRED FOR PEPCO, DPL AND ACE AS THEY MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTION H(1)(a) AND (b) OF FORM 10-Q AND THEREFORE ARE FILING THIS FORM WITH A REDUCED FILING FORMAT.

Item 4. CONTROLS AND PROCEDURES

Conclusions Regarding the Effectiveness of Disclosure Controls and Procedures

Each Reporting Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in such Reporting Company's reports under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to management of such Reporting Company, including such Reporting Company's Chief Executive Officer (CEO) and Chief Financial Officer (CFO), as appropriate, to allow timely decisions regarding required disclosure. This control system, no matter how well designed and operated, can provide only reasonable assurance that the objectives of the control system are met. Such Reporting Company's disclosure controls and procedures were designed to provide reasonable assurance of achieving their stated objectives. Under the supervision, and with the participation of management, including the CEO and the CFO, each Reporting Company has evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of September 30, 2013, and, based upon this evaluation, the CEO and the CFO of such Reporting Company have concluded that these disclosure controls and procedures are effective to provide reasonable assurance that material information relating to such Reporting Company and its subsidiaries that is required to be disclosed in reports filed with, or submitted to, the SEC under the Exchange Act (i) is recorded, processed, summarized and reported within the time periods specified by the SEC rules and forms and (ii) is accumulated and communicated to management, including its CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

Reports of Changes in Internal Control Over Financial Reporting

Under the supervision and with the participation of management, including the CEO and CFO of each Reporting Company, each such Reporting Company has evaluated changes in internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the three months ended September 30, 2013, and has concluded there was no change in such Reporting Company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, such Reporting Company's internal control over financial reporting.

Part II OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

Pepco Holdings

Other than ordinary routine litigation incidental to its and its subsidiaries' business, PHI is not a party to, and its subsidiaries' property is not subject to, any material pending legal proceedings except as described in Note (14), "Commitments and Contingencies," to the consolidated financial statements of PHI included herein, which description is incorporated by reference herein.

Pepco

Other than ordinary routine litigation incidental to its business, Pepco is not a party to, and its property is not subject to, any material pending legal proceedings except as described in Note (11), "Commitments and Contingencies," to the financial statements of Pepco included herein, which description is incorporated by reference herein.

DPL

Other than ordinary routine litigation incidental to its business, DPL is not a party to, and its property is not subject to, any material pending legal proceedings except as described in Note (13), "Commitments and Contingencies," to the financial statements of DPL included herein, which description is incorporated by reference herein.

ACE

Other than ordinary routine litigation incidental to its business, ACE is not a party to, and its property is not subject to, any material pending legal proceedings except as described in Note (12), "Commitments and Contingencies," to the consolidated financial statements of ACE included herein, which description is incorporated by reference herein.

Item 1A. RISK FACTORS

For a discussion of the risk factors applicable to each Reporting Company, please refer to Part I, Item 1A. "Risk Factors" in each Reporting Company's 2012 Form 10-K. There have been no material changes to any Reporting Company's risk factors as disclosed in the 2012 Form 10-K, except as set forth below.

Facilities and related systems may not operate as planned or may require significant capital or operation and maintenance expenditures, which could decrease revenues or increase expenses.

Operation of the Pepco, DPL and ACE transmission and distribution facilities and related systems involves many risks, including: the breakdown or failure of equipment; accidents; labor disputes; theft of copper wire or pipe; scams; failure of computer systems, software or hardware; and performance below expected levels. Older facilities, systems and equipment, even if maintained in accordance with sound engineering practices, may require significant capital expenditures for additions or upgrades to provide reliable operations or to comply with changing environmental requirements. Thefts of copper wire or pipe, which seek to capitalize on the current high market price of copper, increase the likelihood of poor system voltage control, electricity and streetlight outages, damage to equipment and property, and injury or death, as well as increasing the likelihood of damage to fuel lines, which can create an unsafe and potentially explosive condition. Natural disasters and weather, including tornadoes, hurricanes and snow and ice storms, also can disrupt transmission and distribution systems. Disruption of the operation of transmission or distribution facilities and related systems can reduce revenues and result in the incurrence of additional expenses that may not be recoverable from customers or through insurance. Upgrades and improvements to computer systems and networks may require substantial amounts of management's time and financial resources to complete, and may also result in system or network defects or operational errors due to the inexperience of using a new or upgraded system.

PHI is replacing customers' existing electric and gas meters with an AMI system. In addition to the replacement of existing meters, the AMI system involves the construction of a wireless network across the service territories of PHI's utility subsidiaries and the implementation and integration of new and existing information technology systems to collect and manage data made available by the advanced meters. The implementation of the AMI system involves a combination of technologies provided by multiple vendors. If the AMI system results in lower than projected performance, PHI's utility subsidiaries could experience higher than anticipated maintenance expenditures.

A January 2013 court decision involving lease transactions could impact our ongoing litigation against the IRS involving certain cross-border energy lease investments, which may have a material negative impact on our results of operations and financial condition. (PHI only).

Prior to July 2013, PCI maintained a portfolio of cross-border energy lease investments involving public utility assets located outside of the United States, which as of December 31, 2012, had a net investment value of approximately $1.2 billion. PHI's cross-border energy lease investments, each of which was with a tax-indifferent party, have been under examination by the IRS as part of normal PHI federal income tax audits. In connection with the audits of PHI's federal income tax returns from 2001 to 2008, the IRS disallowed the depreciation and interest deductions in excess of rental income claimed by PHI with respect to its cross-border energy lease investments. In addition, the IRS has sought to recharacterize the leases as loan transactions. PHI commenced litigation in the U.S. Court of Federal Claims in January 2012 regarding the disallowance of certain tax benefits claimed by PHI on its federal tax returns for 2001 and 2002.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit issued an opinion in *Consolidated Edison Company of New York, Inc. & Subsidiaries v. United States* (to which PHI is not a party) that disallowed tax benefits associated with a lease-in, lease-out transaction. Under applicable accounting standards, the financial statement recognition of the tax benefits of PHI's uncertain tax position associated with the cross-border energy lease investments is permitted only if it is more likely than not that the position will be sustained. Further, the carrying value of the cross-border energy lease investments must be recalculated if there is a change or a projected change in the timing of the estimated tax benefits generated from these investments.

After analyzing the *Consolidated Edison* ruling, PHI has determined that its tax position with respect to the tax benefits associated with the cross-border energy leases no longer met the more-likely-than-not standard of recognition for accounting purposes. Accordingly, PHI recorded a non-cash charge of $377 million (after-tax) in the first quarter of 2013, consisting of a charge to reduce the carrying value of the cross-border energy lease investments and a charge to reflect the anticipated additional interest expense related to changes in its estimated federal and state income tax obligations for the period over which the tax benefits may be disallowed.

After consideration of certain tax benefits arising from matters unrelated to these lease investments, PHI estimated that, as of March 31, 2013, it would have been obligated to pay approximately $192 million in additional federal and state taxes and approximately $50 million of interest on the additional federal and state taxes. In order to mitigate PHI's ongoing interest costs associated with the $242 million estimate of additional taxes and interest, PHI made an advanced payment to the IRS of $242 million in the first quarter of 2013. While PHI presently believes that it is more likely than not that no penalty will be incurred, the IRS could require PHI to pay a penalty of up to 20% of the amount of additional taxes due. PHI continues to weigh its options with respect to its litigation with the IRS.

In March 2013, PHI began to pursue the early termination of its remaining cross-border energy lease investments with the respective lessees. The early termination of the remaining cross-border energy lease investments was completed in July 2013. The aggregate financial impact of the completion of the early terminations of the cross-border energy lease investments in July 2013 resulted in a pre-tax loss, including transaction costs, of approximately $3 million ($2 million after-tax) for the year ending December 31, 2013.

PHI's subsidiaries are subject to collective bargaining agreements that could impact their business and operations.

As of December 31, 2012, 54% of employees of PHI and its subsidiaries, collectively, were represented by various labor unions. PHI's subsidiaries are parties to five collective bargaining agreements with four local unions that represent these employees. Collective bargaining agreements are generally renegotiated every three to five years, and the risk exists that there could be a work stoppage after expiration of an agreement until a new collective bargaining agreement has been reached. Labor negotiations typically involve bargaining over wages, benefits and working conditions, including management rights. PHI's last work stoppage, a two-week strike by DPL's employees, occurred in 2010. During that strike, DPL used management and contractor employees to maintain essential operations.

One of the collective bargaining agreements to which PHI's subsidiaries are a party was set to expire on June 25, 2013. After a short contract extension, the parties reached a new four-year agreement that was ratified by union members on July 11, 2013. Though PHI believes that protracted work stoppages are unlikely, such an event could result in a disruption of the operations of the affected utility, which could, in turn, have a material adverse effect upon the business, results of operations, cash flow and financial condition of the affected utility and PHI.

The agreements that govern PHI's primary credit facility and various term loan agreements that have been entered into from time to time contain a consolidated indebtedness covenant that may limit discretion of each borrower to incur indebtedness or reduce its equity.

Under the terms of PHI's primary credit facility, of which each Reporting Company is a borrower, and of various term loan agreements that have been entered into from time to time, the consolidated indebtedness of a borrower cannot exceed 65% of its consolidated capitalization. If a borrower's equity were to decline or its debt were to increase to a level that caused its debt to exceed this limit, lenders under the credit facility would be entitled to refuse any further extension of credit and to declare all of the outstanding debt under the credit facility or the term loan immediately due and payable. To avoid such a default, a waiver or renegotiation of this covenant would be required, which would likely increase funding costs and could result in additional covenants that would restrict each Reporting Company's operational and financing flexibility.

Each borrower's ability to comply with this covenant is subject to various risks and uncertainties, including events beyond the borrower's control. For example, events that could cause a reduction in PHI's equity include, without limitation, potential IRS taxes, interest and penalties associated with PHI's cross-border energy lease investments or a significant write-down of PHI's goodwill. Even if each borrower is able to comply with this covenant, the restrictions on its ability to operate its business in its sole discretion could harm its and PHI's business by, among other things, limiting the borrower's ability to incur indebtedness or reduce equity in connection with financings or other corporate opportunities that it may believe would be in its best interests or the interests of PHI's stockholders to complete.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Pepco Holdings

None.

INFORMATION FOR THIS ITEM IS NOT REQUIRED FOR PEPCO, DPL AND ACE AS THEY MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTION H(1)(a) AND (b) OF FORM 10-Q AND THEREFORE ARE FILING THIS FORM WITH A REDUCED FILING FORMAT.

Item 3. DEFAULTS UPON SENIOR SECURITIES

Pepco Holdings

None.

INFORMATION FOR THIS ITEM IS NOT REQUIRED FOR PEPCO, DPL AND ACE AS THEY MEET THE CONDITIONS SET FORTH IN GENERAL INSTRUCTION H(1)(a) AND (b) OF FORM 10-Q AND THEREFORE ARE FILING THIS FORM WITH A REDUCED FILING FORMAT.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

Item 5. OTHER INFORMATION

Pepco Holdings

None.

Pepco

None.

DPL

None.

ACE

None.

Item 6. EXHIBITS

The documents listed below are being filed or furnished on behalf of PHI, Pepco, DPL and/or ACE, as indicated. The warranties, representations and covenants contained in any of the agreements included or incorporated by reference herein or which appear as exhibits hereto should not be relied upon by buyers, sellers or holders of PHI's or its subsidiaries' securities and are not intended as warranties, representations or covenants to any individual or entity except as specifically set forth in such agreement.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
3.1	PHI	Restated Certificate of Incorporation of Pepco Holdings, Inc. (as filed in Delaware)	Exhibit 3.1 to PHI's Form 10-K, March 13, 2006.
3.2	Pepco	Restated Articles of Incorporation (as filed in the District of Columbia)	Exhibit 3.1 to Pepco's Form 10-Q, May 5, 2006.
3.3	Pepco	Restated Articles of Incorporation and Articles of Restatement (as filed in Virginia)	Exhibit 3.3 to PHI's Form 10-Q, November 4, 2011.
3.4	DPL	Restated Certificate and Articles of Incorporation (as filed in Delaware and Virginia)	Exhibit 3.3 to DPL's Form 10-K, March 1, 2007.
3.5	ACE	Restated Certificate of Incorporation (as filed in New Jersey)	Exhibit B.8.1 to PHI's Amendment No. 1 to Form U5B, February 13, 2003.
3.6	PHI	Bylaws	Exhibit 3.6 to PHI's Form 10-K, March 1, 2013.
3.7	Pepco	By-Laws	Exhibit 3.2 to Pepco's Form 10-Q, May 5, 2006.
3.8	DPL	Amended and Restated Bylaws	Exhibit 3.2.1 to DPL's Form 10-Q, May 9, 2005.
3.9	ACE	Amended and Restated Bylaws	Exhibit 3.2.2 to ACE's Form 10-Q, May 9, 2005.
10.1	PHI	Amended and Restated Change in Control / Severance Plan for Certain Executive Employees	Exhibit 10 to PHI's Form 8-K, July 31, 2013.
31.1	PHI	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.2	PHI	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
31.3	Pepco	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.4	Pepco	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
31.5	DPL	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.
31.6	DPL	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
31.7	ACE	Rule 13a-14(a)/15d-14(a) Certificate of Chief Executive Officer	Filed herewith.

Exhibit No.	Registrant(s)	Description of Exhibit	Reference
31.8	ACE	Rule 13a-14(a)/15d-14(a) Certificate of Chief Financial Officer	Filed herewith.
32.1	PHI	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350	Furnished herewith.
32.2	Pepco	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350	Furnished herewith.
32.3	DPL	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350	Furnished herewith.
32.4	ACE	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350	Furnished herewith.
99.1	PHI	Statement Re: Computation of Ratios	Filed herewith.
99.2	Pepco	Statement Re: Computation of Ratios	Filed herewith.
99.3	DPL	Statement Re: Computation of Ratios	Filed herewith.
99.4	ACE	Statement Re: Computation of Ratios	Filed herewith.
101. INS	PHI Pepco DPL ACE	XBRL Instance Document	Filed herewith.
101. SCH	PHI Pepco DPL ACE	XBRL Taxonomy Extension Schema Document	Filed herewith.
101. CAL	PHI Pepco DPL ACE	XBRL Taxonomy Extension Calculation Linkbase Document	Filed herewith.
101. DEF	PHI Pepco DPL ACE	XBRL Taxonomy Extension Definition Linkbase Document	Filed herewith.
101. LAB	PHI Pepco DPL ACE	XBRL Taxonomy Extension Label Linkbase Document	Filed herewith.
101. PRE	PHI Pepco DPL ACE	XBRL Taxonomy Extension Presentation Linkbase Document	Filed herewith.

Regulation S-K Item 10(d) requires registrants to identify the physical location, by SEC file number reference, of all documents incorporated by reference that are not included in a registration statement and have been on file with the SEC for more than five years. The SEC file number references for PHI and each of its subsidiaries that are currently registrants are provided below:

Pepco Holdings, Inc. (File Nos. 001-31403 and 030-00359)
Potomac Electric Power Company (File No. 001-01072)
Delmarva Power & Light Company (File No. 001-01405)
Atlantic City Electric Company (File No. 001-03559)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, each of the registrants has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PEPCO HOLDINGS, INC. (PHI)
POTOMAC ELECTRIC POWER COMPANY (Pepco)
DELMARVA POWER & LIGHT COMPANY (DPL)
ATLANTIC CITY ELECTRIC COMPANY (ACE)
(Registrants)

November 5, 2013

By /s/ FRED BOYLE
Frederick J. Boyle
Senior Vice President and Chief Financial Officer, PHI, Pepco and DPL
Chief Financial Officer, ACE

INDEX TO EXHIBITS FILED HEREWITH OR INCORPORATED BY REFERENCE HEREIN

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32.3	DPL	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350
32.4	ACE	Certificate of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350

Exhibit 31.1

CERTIFICATION

I, Joseph M. Rigby, certify that:

1. I have reviewed this report on Form 10-Q of Pepco Holdings, Inc.;
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.

Date: November 5, 2013

/s/ JOSEPH M. RIGBY
Joseph M. Rigby
Chairman of the Board, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Frederick J. Boyle, certify that:

1. I have reviewed this report on Form 10-Q of Pepco Holdings, Inc.;

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.

Date: November 5, 2013

/s/ FRED BOYLE
Frederick J. Boyle
Senior Vice President and Chief Financial Officer

Exhibit 31.3

CERTIFICATION

I, David M. Velazquez, certify that:

1. I have reviewed this report on Form 10-Q of Potomac Electric Power 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.

Date: November 5, 2013

/s/ DAVID M. VELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

Exhibit 31.4

CERTIFICATION

I, Frederick J. Boyle, certify that:

1. I have reviewed this report on Form 10-Q of Potomac Electric Power 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.

Date: November 5, 2013

/s/ FRED BOYLE
Frederick J. Boyle
Senior Vice President and Chief Financial Officer

Exhibit 31.5

CERTIFICATION

I, David M. Velazquez, certify that:

1. I have reviewed this report on Form 10-Q of Delmarva Power & Light 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.

Date: November 5, 2013

/s/ DAVID M. VELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

Exhibit 31.6

CERTIFICATION

I, Frederick J. Boyle, certify that:

1. I have reviewed this report on Form 10-Q of Delmarva Power & Light 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.

Date: November 5, 2013

/s/ FRED BOYLE
Frederick J. Boyle
Senior Vice President and Chief Financial Officer

Exhibit 31.7

CERTIFICATION

I, David M. Velazquez, certify that:

1. I have reviewed this report on Form 10-Q of Atlantic City Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 5, 2013

/s/ DAVID M. VELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

Exhibit 31.8

CERTIFICATION

I, Frederick J. Boyle, certify that:

1. I have reviewed this report on Form 10-Q of Atlantic City Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 5, 2013

/s/ FRED BOYLE
Frederick J. Boyle
Chief Financial Officer

Exhibit 32.1

Certificate of Chief Executive Officer and Chief Financial Officer

of

Pepco Holdings, Inc.

(pursuant to 18 U.S.C. Section 1350)

I, Joseph M. Rigby, and I, Frederick J. Boyle, each certify that, to the best of my knowledge, (i) the Quarterly Report on Form 10-Q of Pepco Holdings, Inc. for the quarter ended September 30, 2013, filed with the Securities and Exchange Commission on the date hereof fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Pepco Holdings, Inc.

November 5, 2013	/s/ JOSEPH M. RIGBY
	Joseph M. Rigby
	Chairman of the Board, President and Chief Executive Officer
November 5, 2013	/s/ FRED BOYLE
	Frederick J. Boyle
	Senior Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Pepco Holdings, Inc. and will be retained by Pepco Holdings, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

Certificate of Chief Executive Officer and Chief Financial Officer

of

Potomac Electric Power Company

(pursuant to 18 U.S.C. Section 1350)

I, David M. Velazquez, and I, Frederick J. Boyle, each certify that, to the best of my knowledge, (i) the Quarterly Report on Form 10-Q of Potomac Electric Power Company for the quarter ended September 30, 2013, filed with the Securities and Exchange Commission on the date hereof fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Potomac Electric Power Company.

November 5, 2013	/s/ DAVID M. VELAZQUEZ David M. Velazquez President and Chief Executive Officer
November 5, 2013	/s/ FRED BOYLE Frederick J. Boyle Senior Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Potomac Electric Power Company and will be retained by Potomac Electric Power Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.3

Certificate of Chief Executive Officer and Chief Financial Officer

of

Delmarva Power & Light Company

(pursuant to 18 U.S.C. Section 1350)

I, David M. Velazquez, and I, Frederick J. Boyle, each certify that, to the best of my knowledge, (i) the Quarterly Report on Form 10-Q of Delmarva Power & Light Company for the quarter ended September 30, 2013, filed with the Securities and Exchange Commission on the date hereof fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Delmarva Power & Light Company.

November 5, 2013	/s/ DAVID M. VELAZQUEZ David M. Velazquez President and Chief Executive Officer
November 5, 2013	/s/ FRED BOYLE Frederick J. Boyle Senior Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Delmarva Power & Light Company and will be retained by Delmarva Power & Light Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.4

Certificate of Chief Executive Officer and Chief Financial Officer

of

Atlantic City Electric Company

(pursuant to 18 U.S.C. Section 1350)

I, David M. Velazquez, and I, Frederick J. Boyle, each certify that, to the best of my knowledge, (i) the Quarterly Report on Form 10-Q of Atlantic City Electric Company for the quarter ended September 30, 2013, filed with the Securities and Exchange Commission on the date hereof fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained therein fairly presents, in all material respects, the financial condition and results of operations of Atlantic City Electric Company.

November 5, 2013	/s/ DAVID M. VELAZQUEZ David M. Velazquez President and Chief Executive Officer
November 5, 2013	/s/ FRED BOYLE Frederick J. Boyle Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Atlantic City Electric Company and will be retained by Atlantic City Electric Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 99.1

PEPCO HOLDINGS, INC.

	Nine Months Ended September 30, 2013	For the Year Ended December 31, 2012	2011	2010	2009	2008
		(millions of dollars)				
Earnings						
Net income from continuing operations	$ 52	$ 218	$ 222	$ 91	$ 163	$ 214
Preferred stock dividend	—	—	—	—	—	—
(Income) or loss from equity investees	(1)	(1)	3	1	(2)	4
Minority interest loss	—	—	—	—	—	—
Income tax expense (benefit) related to continuing operations	280	103	114	(14)	80	96
Pre-tax income for common stock	331	320	339	78	241	314
Add: Fixed charges*	227	286	275	312	332	317
Add: Distributed income of equity investees	—	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—	(1)
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Earnings	$ 558	$ 606	$ 614	$ 390	$ 573	$ 630
***Fixed Charges**						
Interest on long-term debt	$ 200	$ 249	$ 239	$ 269	$ 286	$ 276
Interest capitalized	—	—	—	—	—	1
Other interest	—	—	—	—	—	—
Amortization of debt discount, premium, and expense	11	16	14	21	23	16
Interest component of rentals	16	21	22	22	23	24
Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Fixed charges	$ 227	$ 286	$ 275	$ 312	$ 332	$ 317
Ratio of earnings to fixed charges (a)	2.46	2.12	2.23	1.25	1.73	1.99

(a) Pepco Holdings, Inc. has no preferred equity securities outstanding, therefore the ratio of earnings to fixed charges is equal to the ratio of earnings to combined fixed charges and preferred stock dividends.

Exhibit 99.2

POTOMAC ELECTRIC POWER COMPANY

	Nine Months Ended September 30, 2013	For the Year Ended December 31, 2012	2011	2010	2009	2008
		(millions of dollars)				
Earnings						
Net income for common stock	$ 126	$ 126	$ 99	$ 108	$ 106	$ 116
Preferred stock dividend	—	—	—	—	—	—
(Income) or loss from equity investees	—	—	—	—	—	—
Minority interest loss	—	—	—	—	—	—
Income tax expense	62	48	36	37	76	64
Pre-tax income for common stock	188	174	135	145	182	180
Add: Fixed charges*	91	113	111	111	114	106
Add: Distributed income of equity investees	—	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Earnings	$ 279	$ 287	$ 246	$ 256	$ 296	$ 286
***Fixed Charges**						
Interest on long-term debt	$ 82	$ 101	$ 97	$ 97	$ 99	$ 90
Interest capitalized	—	—	—	—	—	—
Other interest	—	—	—	—	—	—
Amortization of debt discount, premium, and expense	4	5	4	4	4	5
Interest component of rentals	5	7	10	10	11	11
Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Fixed charges	$ 91	$ 113	$ 111	$ 111	$ 114	$ 106
Ratio of earnings to fixed charges (a)	3.07	2.54	2.22	2.31	2.60	2.70

(a) Pepco has no preferred equity securities outstanding, therefore the ratio of earnings to fixed charges is equal to the ratio of earnings to combined fixed charges and preferred stock dividends.

Exhibit 99.3

DELMARVA POWER & LIGHT COMPANY

	Nine Months Ended September 30, 2013	For the Year Ended December 31, 2012	2011	2010	2009	2008
		(millions of dollars)				
Earnings						
Net income for common stock	$ 61	$ 73	$ 71	$ 45	$ 52	$ 68
Preferred stock dividend	—	—	—	—	—	—
(Income) or loss from equity investees	—	—	—	—	—	—
Minority interest loss	—	—	—	—	—	—
Income tax expense	39	44	42	31	16	45
Pre-tax income for common stock	100	117	113	76	68	113
Add: Fixed charges*	41	52	49	48	47	43
Add: Distributed income of equity investees	—	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Earnings	$ 141	$ 169	$ 162	$ 124	$ 115	$ 156
***Fixed Charges**						
Interest on long-term debt	$ 36	$ 45	$ 42	$ 43	$ 42	$ 38
Interest capitalized	—	—	—	—	—	—
Other interest	—	—	—	—	—	—
Amortization of debt discount, premium, and expense	2	4	4	3	3	3
Interest component of rentals	3	3	3	2	2	2
Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Fixed charges	$ 41	$ 52	$ 49	$ 48	$ 47	$ 43
Ratio of earnings to fixed charges (a)	3.44	3.25	3.31	2.58	2.45	3.63

(a) DPL has no preferred equity securities outstanding, therefore the ratio of earnings to fixed charges is equal to the ratio of earnings to combined fixed charges and preferred stock dividends.

Exhibit 99.4

ATLANTIC CITY ELECTRIC COMPANY

	Nine Months Ended September 30, 2013	For the Year Ended December 31, 2012	2011	2010	2009	2008
		(millions of dollars)				
Earnings						
Net income for common stock	$ 41	$ 35	$ 39	$ 53	$ 41	$ 64
Preferred stock dividend	—	—	—	—	—	—
(Income) or loss from equity investees	—	—	—	—	—	—
Minority interest loss	—	—	—	—	—	—
Income tax expense	14	18	33	43	17	30
Pre-tax income for common stock	55	53	72	96	58	94
Add: Fixed charges*	55	75	74	69	72	67
Add: Distributed income of equity investees	—	—	—	—	—	—
Subtract: Interest capitalized	—	—	—	—	—	—
Subtract: Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Earnings	$ 110	$ 128	$ 146	$ 165	$ 130	$ 161
***Fixed Charges**						
Interest on long-term debt	$ 50	$ 69	$ 69	$ 63	$ 67	$ 60
Interest capitalized	—	—	—	—	—	—
Other interest	—	—	—	—	—	—
Amortization of debt discount, premium, and expense	2	2	2	3	2	4
Interest component of rentals	3	4	3	3	3	3
Pre-tax preferred stock dividend requirement	—	—	—	—	—	—
Fixed charges	$ 55	$ 75	$ 74	$ 69	$ 72	$ 67
Ratio of earnings to fixed charges (a)	2.00	1.71	1.97	2.39	1.81	2.40

(a) ACE has no preferred equity securities outstanding, therefore the ratio of earnings to fixed charges is equal to the ratio of earnings to combined fixed charges and preferred stock dividends.